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The Brattle Group

Second Performance Assessment of PJM's Reliability Pricing Model

Market Results 2007/08 through 2014/15

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EXECUTIVE SUMMARY

The Brattle Group has been commissioned by PJM Interconnection L.L.C. ("PJM") to evaluate the performance of its Reliability Pricing Model ("RPM"), as required periodically under the PJM tariff. The scope of our evaluation includes: (1) a review of all Base Residual Auctions ("BRAs") and Incremental Auctions ("IAs") conducted to date to assess RPM's effectiveness in encouraging and sustaining sufficient capacity investments for reliability; (2) stakeholder interviews to identify key areas of concern; (3) an engineering cost estimate of the Cost of New Entry ("CONE") for each of five CONE Areas; (4) an evaluation of individual RPM design elements, including the Variable Resource Requirement ("VRR") curve, the Energy and Ancillary Service ("E&AS") offset methodology, and other design elements identified by stakeholders; (5) a probabilistic simulation analysis of RPM's performance; and (6) development of recommendations for possible modifications to improve the effectiveness of RPM.

Our primary finding is that RPM is performing well. Despite concerns by some stakeholders, RPM has been successful in attracting and retaining cost-effective capacity sufficient to meet resource adequacy requirements. Resource adequacy requirements have been met or exceeded in both the Regional Transmission Organization ("RTO") and, during the last four BRAs, in all of the individual Locational Deliverability Areas ("LDAs") at capacity prices below the net cost of new entry ("Net CONE"). Year-to-year capacity price changes have been consistent with market fundamentals, reflecting changes in the supply and demand for capacity. RPM has reduced costs by fostering competition among all types of new and existing capacity, including demand-side resources. It has also facilitated decisions regarding the economic tradeoffs between investment in environmental retrofits on aging coal plants or their retirement.

Stakeholders have raised a number of key concerns. We find, however, that several major criticisms of RPM are contradicted by evidence available to date—most notably the arguments that RPM prices are too high, that RPM does not support investment in new generation of the right types in the right places, or that RPM cannot maintain reliability in the face of environmental retirements. Stakeholders expressed particular concerns about the volatility and unpredictability of RPM prices. Some of the observed price changes are consistent with changes in market fundamentals, which necessarily must be reflected in prices for the market to be efficient. Others are caused by the one-time implementation of various improvements to the initial RPM design, such as modeling more LDAs or elimination of Interruptible Load for Reliability ("ILR"). These impacts on prices reflect a non-recurring one-time adjustment, which is not a concern going forward. However, price uncertainty remains high due to non-transparent, and possibly excessive, fluctuations in modeled transmission limits and other administratively-defined parameters in RPM. We thus recommend a number of refinements to make the determination of transmission limits and administrative parameters more stable and transparent. To increase forward price transparency and facilitate long-term contracting, we also support the development of voluntary auctions or an over-the-counter trading platform for long-term capacity products.

Finally, we have identified several performance risks stemming from the RPM design that should be addressed to ensure that resource adequacy will be met going forward. To address these concerns, we recommend the implementation of six safeguards that would mitigate the identified performance risks. First, we recommend calibrating the E&AS offset methodology to E&AS margins actually earned by generation plants similar to the reference technology, which may increase Net CONE in some LDAs. Second, we recommend raising the price cap of the VRR curve to mitigate under-procurement risks. The higher cap will avoid the collapse of the VRR curve following anomalously high E&AS margins, which could result in reserve margins that remain well below reliability requirements. The higher cap will also avoid deterring offers with costs that temporarily exceed the *current* cap due to large differences between actual and administrative Net CONE values. Third, we recommend modeling constrained LDAs more proactively for locations where significant amounts of plant retirements are likely.

Fourth, we recommend maintaining the 2.5% overall Short-Term Resource Procurement Target ("STRPT") for the total resource requirement, but eliminating the "holdback" for Annual and Extended Summer resources. Fifth, we recommend introducing audits of demand-side resources to confirm their contractual and physical ability to respond as often and seasonally as claimed. And finally, we recommend establishing exemptions to the Minimum Offer Price Rule ("MOPR") to better support competitive entry through bilateral and self-supply arrangements.

The report explains these and other more minor recommendations for possible refinements to the RPM design that could further improve market efficiency. It also summarizes the results of the CONE study we conducted, including our recommendations about the choice between levelization methods. The detailed engineering cost study is documented in our separate report, *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM* ("CONE Report").

A. RPM Auction Results to Date

RPM introduced a capacity market design based on three-year forward annual auctions for locational capacity, with supply offers clearing against a downward sloping demand curve (the VRR curve). RPM is designed to achieve resource adequacy, improve price stability compared to the previous capacity market construct, and force existing resources to compete with a potentially large supply of new resources.

We previously assessed the overall effectiveness of RPM in our 2008 *Review of PJM's Reliability Pricing Model (RPM)*, which documented RPM auction results for the first five delivery years; from 2007/08 through 2011/12. Since then, three more base auctions have been conducted; the latest in May 2011 for the 2014/15 delivery year.

Based on our analysis of all RPM auctions conducted to date, we present the following findings:

- RPM has attracted and retained sufficient capacity to maintain resource adequacy in the RTO and in all LDAs, in spite of environmental and other challenges faced by suppliers. All regions have demonstrated capacity supplies in excess of their reliability

requirements in all delivery years for which procurement was undertaken on a full three-year forward basis. Capacity resources were slightly below the reliability requirements during the first few delivery years in some LDAs, reflecting existing supply largely determined by pre-RPM conditions and a shorter-term forward procurement during the first four auctions that prevented most planned capacity from participating.

- Since RPM was implemented, a total of 28,400 MW of installed capacity ("ICAP") from new resources have been committed on an RTO-wide basis (not counting resources from Fixed Resource Requirement ("FRR") entities and new PJM members, FirstEnergy and Duke). These additions consist of 11,800 MW of demand side resources, 6,900 MW of increased imports and decreased exports, 4,800 MW of new generation, 4,100 MW of plant uprates, and 800 MW of plant reactivations. These resource additions are partially offset by 5,000 MW of retirements, 2,700 MW of plant derates, 6,800 MW of capacity initially offered into the RPM auctions by FRR entities but that was subsequently withdrawn to serve the entities own requirements, and 700 MW of otherwise excused resources. On net, the amount of committed capacity has increased by 13,100 MW, more than enough to meet reliability requirements.

- Similarly in all of the LDAs, net resource additions (including upgrades in transmission import capabilities) have been more than sufficient to meet reliability requirements. This occurred even in eastern LDAs, which showed resource deficiencies (relative to their reliability requirements) in the auctions for the first four delivery years. Furthermore, all areas have had significant amounts of uncleared offers from both new and existing resources, including new generation resources, that could have been procured at higher prices had those supplies been needed for reliability. Perhaps one exception is the PEPCO LDA, where little new generation has been offered, but resource adequacy has been maintained by new demand response ("DR") resources and uprates at prices that were well below the cost of new generation in three of the last four auctions.

- RPM has greatly facilitated competition among various types of capacity resources. The capacity market has attracted commitments from new generation. But it has attracted even larger amounts of new DR resources, retained existing generation, and supported the upgrade of existing plants at prices below the cost of new generation. Competition in RPM's centralized forward auctions has also allowed owners of aging coal plants to make more informed decisions about whether to invest in environmental retrofits or start planning to retire the units, particularly in the most recent auction for the 2014/15 delivery year.

- As a result of offers from a wide variety of new resources, particularly demand response resources, the BRA supply curves have become smoother and less steep over time, mitigating the steep offer curves in the first few auctions. This trend increased competition between resources in the recent auctions and will reduce price volatility going forward.

- Base Residual Auction prices have been consistent with the supply and demand for capacity, including transmission capabilities. Apart from the initial, compressed-schedule forward auctions that were dominated by pre-RPM supply conditions, prices have been below Net CONE because new generation was not needed to maintain resource adequacy given the availability of lower-cost, non-generation alternatives. Nevertheless, auction clearing prices were quite volatile, reflecting changes in market fundamentals, RPM rules, and RPM parameters.

- Clearing prices in the incremental auctions have been persistently below BRA prices, in part reflecting low incremental demand for capacity due to declines in load forecast and increased transmission capabilities. Furthermore, clearing prices and supply curves during the first few incremental auctions appear to have been disconnected from market fundamentals and BRA prices due to deficiencies in the initial auction design. Supply curves observed in the two incremental auctions conducted since the initial design was revised have been more consistent with offers observed in the respective BRAs. In the case of EMAAC, prices have also responded efficiently to declines in LDA import capabilities. Overall, however, the limited experience with the new, revised design does not yet allow for a full analysis of the performance of the incremental auctions.

B. Stakeholder Concerns

We conducted interviews with eight groups of stakeholders: transmission owners, generation owners, electric distributors, end-use customers, other suppliers, financial analysts, state utility commissions, and PJM's Independent Market Monitor. The concerns they raised covered a wide range of topics. Stakeholder comments largely agreed on concerns over: (1) the uncertainty and unpredictability of RPM prices; (2) the volatility and lack of transparency in the determination of Capacity Emergency Transfer Limits ("CETL"); (3) the need for better coordination between RPM and transmission planning; (4) a lack of long-term contracting and the need to facilitate such contracting; (5) the potential impacts of EPA's new environmental rules; and (6) challenges created by the use of a historical E&AS offset.

Stakeholder opinions were divided, however, on a variety of topics, including concerns about: (1) a lack of new generation; (2) the treatment of existing and new capacity; (3) the level of CONE estimates; (4) load forecasts and reliability requirements; (5) the shape of the VRR curve; (6) the 2.5% short-term procurement target; (7) the performance and treatment of demand-response resources; (8) the appropriate number of LDAs; (9) the appropriateness of the length of the 3-year forward procurement period between the BRA and the delivery year; (10) how to facilitate long-term contracting; and (11) the efficiency and unintended consequences of the new Minimum Offer Pricing Rule ("MOPR").

Concerns raised by stakeholders are addressed throughout our report. While not all of these themes are RPM design issues, they nevertheless relate directly to capacity procurement costs and price uncertainty in the RPM market. These themes include RPM price uncertainty created by administrative parameters, the need for and the industry trends in long-term contracting, compensation for existing and new generation, the uncertainty created by the new environmental

regulations, the dependability of DR, and the determination of reliability targets. Our findings in these areas are:

- *Price Volatility and Uncertainty.* Capacity prices have been volatile and uncertain, which increases the risks and therefore the costs faced by suppliers. Main causes are: (1) market fundamentals, whose effects on price signals should not be dampened; (2) the implementation of improvements to previous design elements regarding DR participation and LDA modeling which had a non-recurring impact on capacity prices; and (3) current methods of determining the value of administrative parameters, including CETL, locational reliability requirements, and load forecasts, which PJM should strive to make more stable and/or transparent.

- *The Lack of Long-Term Contracts.* Many generation projects proposed in PJM cannot obtain financing under the current market conditions. However, while some project developers may cast this as a market failure caused by the inadequacies of RPM or state retail choice constructs, we believe the primary reason that these projects cannot obtain financing is that they are not currently needed and are currently uncompetitive with alternative sources of capacity. In the future, when these projects are needed for resource adequacy, we expect that market prices will rise sufficiently to make these investments attractive. Nevertheless, we also recognize that it will be beneficial to both suppliers and customers if long-term contracts are facilitated and not hindered by RPM design and state retail regulation. To address long-term contracting concerns, we present options for increasing forward price transparency and offer recommendations to mitigate the perhaps unintended consequences of the recent modifications to MOPR.

- *Equal Compensation for Old and New Generation.* A number of state commissions expressed concern that RPM has maintained old generating plants with high emissions, compensating them as much as newer generation. With regard to environmental issues, we find that RPM is well designed to respond to existing environmental regulations and has successfully retained generation that complies with these existing standards. RPM should not be expected to serve as an indirect mean to impose tighter environmental standards than the state and federal governments have deemed appropriate. Moreover, trying to differentiate payments based on age would be inconsistent with a construct in which all resources are selling the same capacity product, and would lead to inefficiencies and higher costs in the long term.

- *Environmental Retirements.* Several stakeholders expressed concern about RPM's ability to replace or prevent simultaneous retirements of a large amount of generation caused by EPA's new environmental regulations. To date, RPM has responded well to such challenges due to its retrofit provisions, the forward period, and centralized clearing. So far, RPM has successfully and economically supported resource adequacy for the 2014/15 delivery year when EPA's new regulations become effective and over the 2009 through 2011 timeframe when Maryland implemented its Healthy Air Act. However, significant uncertainties remain as RPM has not yet been tested with larger amounts of simultaneous retirements within individual LDAs. It is consequently too early to tell how

well RPM (or any other construct) will be able to address the challenges caused by the full slate of new EPA regulations planned to take effect between 2015 and 2018. Given the risks, we recommend that PJM continue to monitor potential retirements and implement safeguards such as a more proactive modeling of new LDAs.

- *The Dependability of Demand Response.* Generation and transmission owners expressed the concern that almost 10% of total resources cleared in the 2014/15 auction without assurance that so much DR can be developed and perform. The level of DR capacity committed for the 2014/15 delivery year is approximately 4,000 MW higher (in terms of unforced capacity or "UCAP") than the 10,900 MW of DR, energy efficiency ("EE"), and ILR resources that are already registered for the current 2011/12 delivery year—which appear to have been performing well during the recent heat wave. While substantial, the 4,000 MW increase over the next 3 years compares to a 6,000 MW increase over the past three years. Considering these trends and the fact that penalty provisions for deficiencies and performance violations are roughly comparable to those faced by generation, we anticipate adequate performance on average. However, we also recommend additional safeguards to ensure that all resources can perform as frequently and seasonally as claimed.

- *RPM Procurement Target.* Stakeholders raised concerns about the current methods used to determine the reliability requirement and the load forecast, which together determine the target level of procurement in RPM. We recognize that reviewing the targets themselves is not within the scope of our evaluation. However, in response to stakeholders' concerns, we offer recommendations for further examination of the targets and for improving transparency of the load forecasting process. We also recommend that PJM assess the economic benefits of selected target reserve margins and re-evaluate whether the 1-in-25 LDA reliability requirement should be modified to explicitly depend on the level of import dependence in the LDA and the probability of transmission outages.

C. Estimates for the Net Cost of New Entry

We recommend maintaining a combustion turbine ("CT") as the reference technology for the determination of Net CONE to define the VRR curve. Based on an examination of plants currently under construction in PJM and the U.S., and an analysis of likely future NO_X emissions standards, the reference plants are assumed to be configured as follows: a 390 MW (summer rating) greenfield CT plant with 2 GE 7FA.05 turbines with selective catalytic reduction ("SCR") for NOx control (only dry low-NO_X burners in Dominion), and evaporative cooling for power augmentation. Combined-cycle ("CC") plants were also evaluated based on a 2x1 configuration using GE 7FA.05 turbines, a cooling tower, SCR, evaporative cooling, and a total capacity of approximately 656 MW (summer rating), of which 72 MW is associated with duct firing.

For these CT and CC plant designs, we developed plant capital costs estimates working with CH2M HILL, a major EPC contractor. CH2M HILL relied on the same engineering cost models it currently uses to bid for actual projects. Resulting estimates of plant capital costs are reported

here for each of five CONE areas of PJM. Details of this analysis are documented in the CONE Report prepared concurrently with this report.

The gross CONE is based on levelized plant capital costs plus estimated fixed operation and maintenance costs. The levelization calculation assumes balance-sheet financing by a merchant generator without a long-term power purchase agreement at an 8.5% after-tax weighted-average cost of capital ("ATWACC") and 20-year cost recovery. In Eastern Mid-Atlantic Area Council ("Eastern MAAC" or "EMAAC") for example, levelized CT costs are $134/kw-year ($367/MW-day) for the 2015/16 delivery year using the "level-nominal" capital charge rate method currently used in the RPM design. Our gross CONE estimate for EMAAC is 6% lower than the $142/kW-year ($389/MW-day) inflation-adjusted gross CONE estimate currently used in RPM.

We recommend that PJM and its stakeholders ***consider transitioning from the current "level-nominal" to a "level-real" capital charge rate methodology***. The "level-real" method assumes that the trajectory of future operating margins will grow with inflation as the net cost of new plants increases, which our analysis shows is consistent with the rate of historical cost increases. This recommendation is contingent on the adoption of our other recommendations (summarized below) to improve the E&AS offset and raise the price cap of the VRR curve. If implemented, the "level-real" capital charge rate would yield a gross CONE for 2015/16 of approximately $112/kW-year ($306/MW-day) for EMAAC. However, we estimate this $30/kW-year ($82/MW-day) decline in gross CONE estimates from the inflation-adjusted, current gross CONE will be approximately fully offset in eastern PJM by a lower, more accurate E&AS offset.

The administratively-determined E&AS offset currently over-estimates the E&AS margins actually earned by plants similar to the reference technology, especially in EMAAC and Southwestern MAAC. We consequently recommend that the ***calculation of the E&AS offset be improved to better reflect actual E&AS margins earned by similar plants***. Options include: (a) calibrating the dispatch algorithm used to estimate E&AS offsets so that it accurately reflects actual units' net revenues (*e.g.*, to incorporate significant participation in day-ahead markets even by CTs) or (b) that the E&AS offset be calculated directly from the net revenues earned by comparable new units (and regardless of whether these representative units are located in the same zone used to develop the gross CONE estimate). To reduce RPM price volatility, improve the timing of investment signals, and increase VRR curve performance, we also recommend that PJM and its stakeholders ***continue to explore options for developing either a normalized, forward-looking E&AS offset or an E&AS offset consistent with "equilibrium" market conditions at target reserve margins***. Finally, we have assessed the potential for an empirical determination of Net CONE based on the bid information from new resources participating in the RPM auctions. Our analysis documents include a very wide range of bid levels, leading us to the conclusion that this information is not useful to develop empirical estimates of Net CONE.

D. Increasing RPM Price Transparency and Stability

Significant changes in market fundamentals, including the unexpected swings in economic conditions, and several RPM design improvements implemented over the last several years have caused substantial swings in capacity prices. However, excess capacity price uncertainty

remains that should be mitigated. The remaining sources of price uncertainty primarily relate to administrative parameters, including unexpected changes in LDA modeling, large and unexpected changes in LDA import constraints (CETL), and unexpected changes in load forecasts.

To reduce excess RPM price volatility, we offer a number of recommendations for further consideration and evaluation by PJM and its stakeholders. They include options that would ***increase CETL transparency and predictability*** (*e.g.*, by providing four, five and ten year CETL projections as part of the transmission planning process) and ***reduce the frequency of large CETL changes*** (*e.g.*, by introducing thresholds that help stabilize transmission plans). We also recommend that PJM and stakeholders consider options to ***improve coordination between RPM and PJM's transmission planning process*** (*e.g.*, by adding economic criteria to the reliability planning process and considering likely plant retirements), to ***minimize the likelihood that resource adequacy concerns related to plant retirements are addressed through reliability-must-run contracts***, and ***facilitate market-based responses to resource adequacy concerns*** that are identified through the transmission planning process.

To increase forward price transparency and facilitate bilateral long-term contracting, we also support PJM's effort to add centralized but voluntary auctions for long-term capacity products as a supplement to the 3-year forward base auctions (*e.g.*, for a duration of 3, 5, and 7 years starting with the BRA delivery year). Such ***voluntary long-term auctions or an over-the-counter trading platform for long-term capacity products*** would increase the transparency and liquidity of the long-term capacity market without risking the kinds of distortions that would be caused to auction prices if the prices for a single delivery year could be locked for multiple years in by broadening the New Entry Pricing Adjustment ("NEPA") or introducing mandatory long-term procurement.

E. Safeguarding Future RPM Performance

While our analyses confirm that PJM has performed well to date, we also identified potential performance concerns. First, probabilistic market simulations identified potential performance problems with the current VRR curve when used in combination with historical E&AS offsets. These performance concerns are related to the current definition of the VRR curve cap (*i.e.*, point "a") as 1.5 × Net CONE. The simulations show that the current design risks the collapse of the entire VRR curve whenever historical energy margins spike (*e.g.*, due to unusual weather, outages, or other unexpected scarcity events). If E&AS offsets reach or exceed the value of CONE, the entire VRR curve disappears (*i.e.*, there is no demand for capacity), which can leave the market "stuck" at reserve margins that remain well below reliability targets. Even without a full collapse of the VRR curve, the current design does not provide the investment signals that can be depended upon to maintain reliability targets. This is the case whenever the historical E&AS offset is high, for example, and the cap of the VRR curve cap drops to levels less than generation developers' actual net cost of new entry.

To guard against such outcomes and maintain investment signals that can reasonably support achieving reliability targets, we recommend that PJM and stakeholders consider ***increasing the***

cap of the VRR curve such that the cap (point "a") exceeds the administratively determined value of Net CONE (point "b") by at least 0.5 × CONE and perhaps by as much as 1.0 × CONE (compared to the current cap, which exceeds point "b" by only 0.5 × Net CONE). This would reduce the likelihood that the cap is too low to attract offers under a variety of circumstances. It would also have avoided a problem encountered in SWMAAC, where a low price cap (relative to the price in the MAAC parent LDA) prevented the LDA from price-separating and continuing to procure local capacity in the 2010/11 auction in spite of shortages. Probabilistic market simulations indicate that increasing the VRR curve cap to 0.5 × CONE above point "b" would likely offset approximately 80% of the performance deterioration associated with the use of historical E&AS offsets. We also recommend that PJM ***clarify that the value of Net CONE cannot drop to levels less than zero*** for the purpose of defining points a, b, and c of the VRR curve and, as noted above, renew efforts to develop a normalized, forward looking or equilibrium E&AS offset.

In addition to modifying the VRR curve, we recommend that PJM and its stakeholders consider implementing a number of additional safeguards:

- ***Proactive LDA modeling.*** To address potential locational resource adequacy challenges created by new environmental rules, we recommend that PJM proactively model LDAs in upcoming incremental and base residual auctions. We recommend that LDAs be modeled as soon as it appears that a significant amount of existing resources may be at risk for retiring within the LDAs. Resources at risk for retirement would be existing generation that did not clear in the most recent BRA or that have otherwise been determined to be at risk for retirement.

- ***Modify the 2.5% Short-Term Resource Procurement Target (STRPT).*** We recommend that PJM maintain the 2.5% overall STRPT but eliminate any "holdback" for Extended Summer and Annual resources. Holding back procurement of 2.5% of these higher-quality resources could suppress prices and lead to resource adequacy challenges in the face of retirement pressures on existing coal plants from new EPA regulations. Overall, we find that the STRPT does not distort capacity prices because more than 2.5% of total resources offered are unmitigated, allowing suppliers to freely adjust their offers or their decisions to participate in BRAs versus incremental auctions.

- ***Resource Verification.*** We recommend that PJM and its stakeholders consider a number of refinements to the existing verification and enforcement provisions for demand-side resources. This would further improve the efficiency of RPM and ensure that all resources can perform as claimed. Our recommendations include testing of DR resources and expanding the resource registration process undertaken prior to each delivery year to include audits of contracts and physical loads to verify the capabilities of zonal resource portfolios to curtail as frequently and seasonally as represented, with appropriately penalties to provide incentives for DR providers to represent their resources accurately. This will allow PJM to confirm that resources can respond as often and seasonally as claimed. For example, this process would verify that resources providing "Annual" DR

can respond in all seasons and do not have contractual limitations on the number of events.

- ***Exemptions from Minimum Offer Price Rule ("MOPR").*** We recognize that MOPR is important for preventing manipulation of RPM prices by buyers. However, we hope that the present proceeding on MOPR expands exemptions to prevent unintended consequences. Exemptions we recommend considering would apply to any capacity resource that is (1) procured under non-discriminatory competitive processes that are open to supplies from existing and new generation resources; or (2) self-supplied by entities that would not obtain net benefits from RPM price impacts, such as vertically-integrated load-serving entities and other resource owners (and their counterparties) that can demonstrate they do not have a significant net short position in RPM.

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I. BACKGROUND

A. Purpose and Scope of this Study

1. *The Brattle Group* has been commissioned by PJM Interconnection L.L.C. ("PJM") to evaluate the performance and the overall design of its Reliability Pricing Model ("RPM"), as required periodically under the PJM tariff. The evaluation criterion is the effectiveness in meeting RPM's objective, which is to enable PJM to obtain sufficient resources to reliably meet the electricity needs of consumers within PJM. Several corollary objectives are to align capacity pricing with system reliability requirements, to provide transparent information to all market participants far enough in advance for actionable response, to support investment in demand-side resources and alternative supply resources as well as generation, to prevent boom-bust cycles in investments, to coordinate between RPM and Regional Transmission Planning ("RTEP"), and to reduce uncertainty in order to lower overall consumer cost to maintain reliable capacity supply in the long run. The specific scope of this assessment included: a review of all Base Residual Auctions ("BRAs") and Incremental Auctions ("IAs") conducted to date (*i.e.*, through the 2014/15 delivery year) to assess the performance and overall effectiveness of RPM in encouraging and sustaining infrastructure investments;
2. Stakeholder interviews to identify key areas for performance assessment;
3. An evaluation of individual RPM design elements, in particular the Variable Resource Requirement ("VRR") curve and the Energy and Ancillary Service ("E&AS") offset methodology;
4. A simulation modeling analysis of the ability of RPM to reduce uncertainty and support investment sufficient to meet reliability requirements on a probabilistic basis;
5. An empirical and an engineering-cost assessment of the Cost of New Entry ("CONE") for each of five CONE Areas; and
6. Developing recommendations for possible modifications (if any) to improve the effectiveness of RPM.

We previously assessed the overall effectiveness of RPM in encouraging and sustaining infrastructure investments, documented the outcomes of the first five BRAs, analyzed the effectiveness of individual market design elements, and presented a number of recommendations for considerations by PJM and its stakeholders. The results of this prior assessment were presented in our June 2008 report reviewing RPM's performance ("2008 RPM Report").[1]

The remainder of this report is organized as follows. We first provide some background on RPM and summarize its current design. Section II discusses RPM auction results in detail, focusing on resource adequacy achieved and price signals sent under RPM. Section III of this report

[1] Pfeifenberger, Newell, Earle, Hajos, and Geronimo, *Review of PJM's Reliability Pricing Model (RPM)*, June 30, 2008.

summarizes comments received in our stakeholder interviews and discusses a number of key themes raised by stakeholders, such as concerns over price volatility and the lack of long-term contracting. Section IV summarizes our analysis of the current Cost of New Entry. Section V presents our analysis of VRR curve, including a probabilistic evaluation of the performance of the VRR curve prepared in cooperation with Professor Benjamin Hobbs based on the simulation model he previously developed and presented. And finally, in Section VI, we analyze a number of RPM and PJM market design elements and, for consideration and further evaluation by PJM and its stakeholders, identify aspects of these design elements that should be adjusted to improve the overall market effectiveness and provide additional safeguards to avoid RPM performance problems and resource adequacy shortfalls in light of future challenges such as the new Environmental Protection Agency ("EPA") regulations and continued reliance on the potentially volatile historical E&AS offsets.

B. RPM Background

As we noted in our 2008 RPM Report, RPM replaced PJM's previous capacity market construct, the Capacity Credit Market ("CCM"), starting with the 2007/08 delivery year. The CCM, which had been in place since 1999, was a voluntary balancing mechanism that allowed Load Serving Entities ("LSEs") to satisfy their installed capacity ("ICAP") requirements on a daily, monthly, and multi-monthly basis. The CCM transacted less than 10% of the total PJM capacity obligation and was based on daily market clearing prices that were uniform across the entire PJM footprint. In addition, this original CCM did not include explicit market power mitigation rules, provided only weak performance incentives, and did not permit the participation of demand-side resources. The CCM resulted in capacity prices that, despite significant occasional spikes, were on average well below both the cost of adding new capacity and the cost of retaining some of the region's existing capacity. Importantly, without recognizing locational reliability requirements, the CCM also did not reflect reliability challenges and the higher value of capacity in certain import-constrained areas of PJM, particularly in parts of eastern PJM, such as the northern New Jersey, Delmarva, and Baltimore-Washington areas.

In contrast to CCM, the RPM capacity market design features a three-year forward-looking annual obligation for locational capacity that designed to improve price stability, enhance reliability, and force existing resources to compete with a potentially large supply of new resources. RPM includes a must-offer requirement for all capacity resources as well as mandatory participation by load. The RPM design also adds stronger performance incentives for generation, explicit market power mitigation rules, and direct participation of demand-side resources. RPM introduced an auction format in which offer-based supply curves are cleared against downward-sloping demand curves (the VRR curves) instead of vertical demand curves. The sloped demand curve design provides a number of benefits, including valuing capacity that is procured beyond that which is required to meet reliability requirements.

The stated purpose of RPM is to enable PJM to obtain sufficient resources to reliably meet the needs of consumers within PJM. In fulfilling that function, PJM emphasizes that the RPM provides:

- Support for load-serving entities (LSEs) using self-supply to satisfy their capacity obligations for future years;

- A competitive auction to secure additional capacity resources, demand response ("DR"), and qualifying transmission upgrades to satisfy LSEs' unforced capacity ("UCAP") obligations that are not satisfied through self-supply;
- Recognition of the locational value of capacity resources; and
- A backstop mechanism to ensure that sufficient generation, transmission and demand response solutions will be available to preserve system reliability.

RPM was approved by the Federal Energy Regulatory Commission ("FERC") in its order dated December 22, 2006 (Docket ER05-1410-001 *et al.*) after an extensive stakeholder and market design effort lasting more than two years. PJM initially filed a proposed RPM market design with FERC on August 31, 2005 to address the failure of the previous capacity market design to set prices adequate to ensure sufficient resources, which caused current and projected violations of PJM's reliability requirement, particularly in eastern PJM. FERC agreed in an April 20, 2006 order that the preexisting capacity market design was unjust and unreasonable and ordered further proceedings which led to settlement discussions involving more than 65 parties. This settlement effort led to the current RPM design that was filed on September 29, 2006 ("RPM Settlement") and approved by FERC in its December 22, 2006 order.

The first RPM auction took place in April 2007 and procured capacity for the 2007/08 delivery year. Four more were conducted within the next 12 months. The fifth auction, conducted in May 2008 auction for the 2011/12 delivery year, was the first to procure capacity under a full three-year forward commitment. Since then, three more auctions have been conducted with a full 3-year forward commitment, the most recent one in May 2011 for the 2014/15 delivery year.

Attachment DD of PJM's Open Access Transmission Tariff ("OATT") and PJM's Manual 18 describe the RPM market design in detail.[2] Various RPM overviews, training materials, and information for individual delivery years, auction design parameters, and summary auction results are also available online.[3] Additional materials, discussion documents, and agendas documenting the ongoing efforts to refine various aspects of RPM are posted under various stakeholder groups, particularly in the Markets and Reliability Committee (MRC).[4] Design overviews and detailed assessments of RPM auction results and performance to date have also been published by PJM's Independent Market Monitor ("IMM").[5]

C. Summary of the Current RPM Design

We provided a detailed description of the RPM design in our 2008 RPM Report, some of which we repeat here for the convenience of providing a complete design summary. The key design parameters of RPM are:

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2 PJM's OATT and capacity market manual are publicly posted, see PJM (2011a, q).

3 For training materials, see "Reliability Pricing Model" in PJM (2011u); for auction results, parameters and related documentation, see PJM (2011v).

4 MRC and other stakeholder group meeting materials are available at PJM (2011w).

5 The market monitor publishes a report on the results of every base and incremental auction, as well as publishing reviews within the annual state of the market reports, see Monitoring Analytics (2011a).

- Base residual and incremental auctions that procure capacity and adjustments to capacity obligations on a forward basis;
- LDAs and locational capacity prices that are able to reflect the greater need for capacity in import-constrained areas;
- Provisions that allow demand-side resources and new transmission projects to compete with generating capacity;
- A downward sloping (rather than a vertical) demand curve, called the VRR curve;
- Administrative and empirical determinations of the net cost of new entry ("Net CONE");
- Performance monitoring during the delivery year and peak periods;
- Consistency with self-supply and bilateral procurement of capacity;
- An opt-out mechanism under the Fixed Resource Requirement (FRR) alternative;
- Explicit market monitoring and mitigation rules, including a must-offer requirement for existing generating resources and IMM review and mitigation of new entrant offers.

Base Residual and Incremental Auctions. The initial auctions procuring forward capacity resources for particular delivery years are referred to as Base Residual Auctions or BRAs, in reference to the fact that the auctions procure the residual resources required after taking into account resources self-supplied by load serving entities through asset ownership or long-term bilateral contracts. Each base auction is followed by three "Incremental Auctions"—23 months, 13 months, and 4 months before each delivery year—that can be used by PJM to procure additional resource (if needed) or by market participants to adjust their BRA commitments.

Conducting the capacity market on a three-year forward basis roughly matches the minimum lead time needed to bring new capacity resources online and the lead time needed to delay or cancel projects before irreversible major financial commitments have been made. This improves price stability and reliability by providing forward market signals that can help avoid periods of extreme scarcity or excess capacity. It also forces existing resources to compete with a potentially large supply of new resources that can be brought online within three years.

Locational Deliverability Areas ("LDAs). LDAs are subregions of PJM with limited import capability due to transmission constraints. If an LDA is constrained, locational capacity prices will exceed the capacity price in the unconstrained part of PJM. Currently there are 25 LDAs defined in RPM, although, as shown in

Figure **1** and Figure 2 show only eight LDAs currently modeled such that capacity auctions could yield different clearing prices. The LDAs currently modeled in PJM are: the unconstrained Regional Transmission Organization ("RTO"); the Mid-Atlantic Area Council ("MAAC") which contains subzones Eastern MAAC ("EMAAC") and Southwestern MAAC ("SWMAAC"); SWMAAC contains the Potomac Electric Power Company ("PEPCO") subzone, SWMAAC also contains the Baltimore Gas and Electric ("BGE") zone, which is not a constrained LDA by itself; EMAAC contains the Delmarva Power and Light Company ("DPL") South ("DPL South") and Public Service Electric and Gas Company ("PSEG") LDAs; and PSEG contains PSEG North.

Figure 1
Constrained Locational Deliverability Areas in RPM

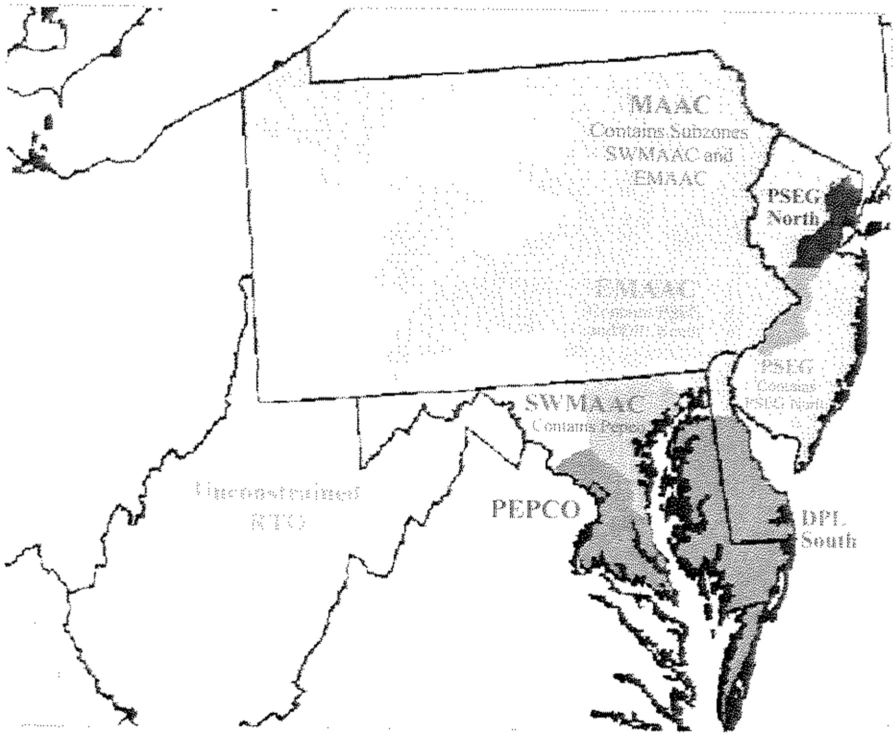


Figure 2
Locational Deliverability Areas and Utility Service Areas

Unconstrained RTO	MAAC	EMAAC	PSEG	SWMAAC	PEPCO
ComEd	MetEd	RECO	PSEG North	BGE	
AEP	PPL	AECO	DPL South		
Duke	Penelec	PECO			
Dayton		JCPL			
First Energy		Northern DPL			
Duquesne					
Allegheny Power					
Dominion					

Sources and Notes:
Modeled LDAs are shown as squares with names in bold; other transmission zones are not currently modeled.
LDA definitions and structure from PJM (2011d), pp. 10-11.

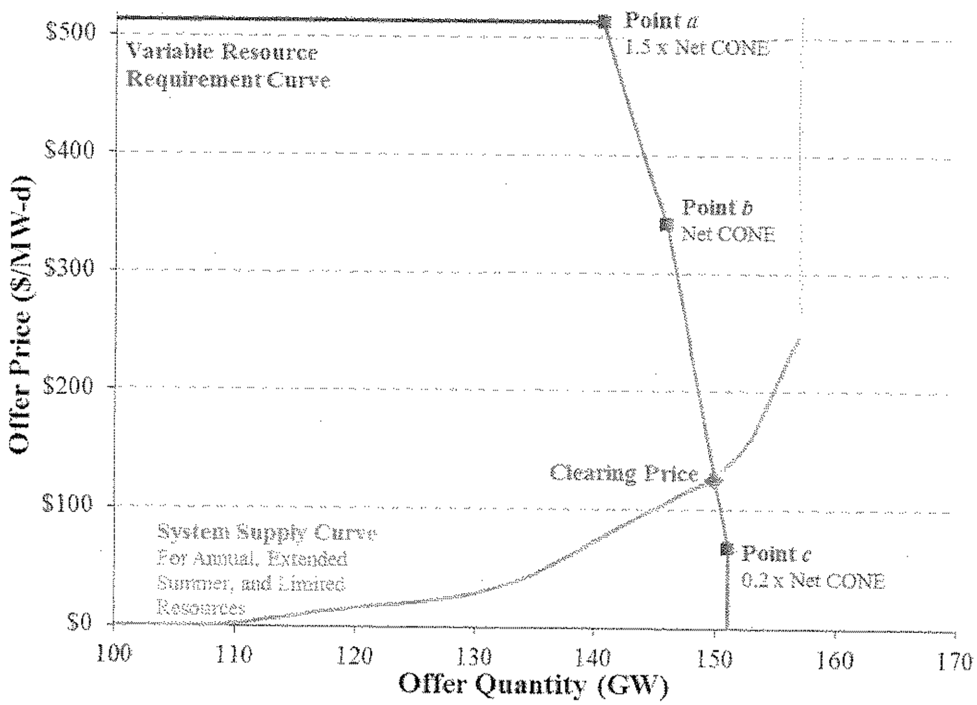
Participation by Demand-Side Resources and New Transmission Upgrades. RPM enables participation by demand-side resources and new transmission projects. Capacity provided by these resources is treated equivalently to generating capacity. Eligible transmission projects,

called Qualifying Transmission Upgrades ("QTUs"), can participate to increase import capability into a constrained LDA.

Downward Sloping Demand Curve. The VRR curve is anchored at point "b" at a price and quantity that reflects the Net CONE and a reserve margin that is one percentage point above the target reserve margin that satisfy regional and locational reliability standards. Net CONE is determined as the annualized fixed cost of new generating capacity *net* of energy and ancillary service ("E&AS") margins.

The VRR curve is designed to yield auction clearing prices in excess of Net CONE when the amount of cleared capacity falls below the target reserve margin needed to satisfy regional and local reliability requirements. Similarly, capacity prices fall below Net CONE when the amount of cleared capacity exceeds target reserve margins. Figure 3 shows the capacity supply curve, VRR curve, and auction clearing price and quantity for the most recent RPM auction, which procured capacity for the 2014/15 delivery year.

Figure 3
Capacity Supply and Demand in the 2014/15 Base Auction



By definition, this VRR curve yields a capacity price equal to Net CONE at the target reserve margin plus 1 percentage point. For lower supply levels, capacity prices increase linearly to reserve margins that are 3 percentage points below target reserve margins, at which point the capacity price is capped at 150% of Net CONE (point "a"). From the price equal to Net CONE at target reserve margins plus 1 percentage point, capacity prices also decline linearly until reserve margins reach target reserves plus 5 percentage points, at which the capacity price is equal to 20% of Net CONE (point "c"). For even higher reserve margins, capacity prices drop to zero.

As was noted in the FERC order approving the RPM design,[6] compared to a system that simply attempts to procure capacity to satisfy a target reserve margin (*i.e.*, a vertical demand curve), the downward-sloping demand curve is designed to provide the following advantages:

- The downward-sloping VRR curve reduces capacity price volatility because capacity prices change gradually as capacity supplies vary over time. The lower volatility due to a sloped demand curve should render capacity investment less risky, thereby encouraging greater investment at a lower cost.

- The sloped demand curve provides a better indication of the incremental and decremental value of capacity at different planning reserve margins. The sloping VRR curve recognizes that incremental capacity above the target reserve margin provides additional reliability benefit, albeit at a declining rate.

- The sloped VRR curve also mitigates the potential exercise of market power by reducing the incentive for suppliers to withhold capacity when aggregate supply is near the target reserve margin. Withholding capacity is less profitable under a sloped demand curve close to the target reserve requirements than under a vertical one because withholding would result in a smaller increase in capacity prices.

Determination and Adjustments of CONE. The value of CONE is estimated as the levelized cost (currently defined in constant nominal dollar terms) that a new entrant needs to recover in power markets—including energy, ancillary service, and the RPM capacity market—to recover its investment costs. The PJM Tariff allows for periodic review and adjustment of the CONE parameter through a combination of index-based adjustment and periodic updates based on engineering cost studies.

Energy and Ancillary Services Revenue Offset. The E&AS offset represents the administratively-estimated net profit that a new entrant with the reference technology earns from the sale of energy and ancillary services. E&AS offsets are used to calculate Net CONE which reflects the amount of annual capacity market revenue that the new entrant needs for profitable entry. Under current RPM rules, E&AS offsets are calculated as a three-year average of estimated historical profits for the reference technology.

Performance Monitoring. The market clearing price is paid to all capacity committed in an auction. However, these payments can be partially, fully, or more than fully offset by performance-based penalties that depend both on the resources' general availability during the delivery year as well as their availability during peak periods when the reliability value of capacity is the greatest. The combination of these payments and penalties is designed to ensure that suppliers have the proper incentives to make their resources available to PJM during reliability events.

Self-Supply and Bilateral Procurement of Capacity. The RPM market design allows LSEs to self-supply resources to meet their capacity obligations either by designating resources they own or purchase bilaterally. Such capacity must be offered into base auctions. The main purpose of the base auctions is to purchase capacity needs not met by self-supplied resources.

[6] December 2006 RPM Order at ¶¶75-76.

Fixed Resource Requirement. The FRR alternative allows LSEs to opt out of RPM and, instead, meet a fixed capacity obligation. LSEs that choose the FRR option are subject to certain qualification requirements and face restrictions on the amount of capacity they may sell in RPM auctions.

Market Mitigation. Sell offers of existing capacity resources in RPM auctions are subject to mitigation. Offers can be mitigated to a level that reflects each individual unit's going-forward, avoidable costs. Sell offers by planned resources are not subject to offer caps, but may be rejected by the MMU if they are found to be uncompetitive.

Changes to the RPM design since our 2008 RPM Review. Since we reviewed RPM performance in 2008, PJM implemented a number of refinements to the RPM design and related elements, including the following:

- Two new CONE Areas and a revised CONE update process to by using annual adjustments based on the Handy-Whitman cost index with CONE updates based on engineering studies only every three years.

- RPM procurement targets and FRR obligations that can increase or decrease after the BRA based on changes in load forecast prior to the delivery year (previously the BRA Preliminary Obligation was the floor). Reallocation of capacity obligations of individual load zones prior to delivery years based on changes in peak loads since BRA.

- A number of modifications specifying when and how LDAs are modeled in RPM auctions, including (1) a requirement to model all regional LDAs in each auction (2) the increase in the Capacity Emergency Transfer Limits ("CETL")/ Capacity Emergency Transfer Objective ("CETO") threshold for modeling other LDAs from 105% to 115%; (3) revised guidelines to create new LDAs (Manual 14B); and (4) incorporation of planned transmission additions into CETL only when there is a reasonable expectation that the project can be online as anticipated.

- Revisions to RPM Auction designs, including (1) the addition of the 2.5% Short Term Resource Procurement Target; (2) improved structure and expanded scope of incremental auctions; and (3) separate clearing of limited summer, unlimited summer and annual capacity products.

- Reduced performance penalties to 1.2 times the higher of: (1) the auction resource clearing price in which the capacity was originally cleared; and (2) the third incremental auction resource clearing price.

- A streamlined generation interconnection process that allows planned resources to qualify for RPM more quickly.

- Options that allow market participants to combine individual partial-year resources as annual resources.

- Revisions to how demand-response resources are integrated into the RPM design, including (1) the elimination of ILR to encourage DR participation in BRAs; (2) elimination of offer caps for DR resources; (3) the creation of multiple DR products

(limited summer, extended summer, and annual); (4) accommodation of energy efficiency ("EE") resources; (5) testing of DR resources.

- Revisions to the minimum offer price rule ("MOPR") to guard against suppression of RPM clearing prices through the addition of uneconomic generating capacity.

A number of other refinements, such as improved validation and verification processes for generation and demand resources, modifications of how capacity cost responsibilities are allocated to load serving entities ("LSEs"), and modifications to the New Entry Pricing Adjustment ("NEPA") that provide certainty that new resources will clear in subsequent auctions.

II. ANALYSIS OF MARKET RESULTS

This section documents and analyzes market results under RPM to date. First, we analyze the outcomes under each of the eight base residual auctions (BRAs) and seven incremental auctions (IAs) that have been conducted since RPM was implemented, starting with the 2007/08 delivery year. For each of these auctions, we report the clearing prices and the quantities of cleared and uncleared offers by resource type and location. We also explain the causes of price changes over time. Next, we document the cumulative changes in committed capacity since RPM's inception through 2014/15, the latest delivery year covered by the most recent BRA. Finally, we examine the quantity of proposed new generating projects that are currently under study in the generation interconnection queue as an indicator of potential new additions beyond those already committed through RPM.

Our analysis of market results demonstrates that sufficient capacity has been procured under RPM to ensure resource adequacy at prices consistent with locational market conditions. While moderate capacity deficits initially occurred in some LDAs due primarily to pre-RPM conditions, the last four BRAs have cleared more than sufficient capacity in each LDA. Since RPM was implemented, a cumulative 28.4 GW of gross committed capacity and 13.1 GW of net committed capacity (in ICAP terms) has been added under RPM, excluding FRR capacity and the addition of new PJM members, FirstEnergy and Duke. All auction results are reported in UCAP terms in Sections II.A and II.B below, while the cumulative capacity changes under RPM are reported in ICAP terms in Section II.C.

A. Base Residual Auction Results

Most capacity under RPM is procured through the base residual auctions. Base auctions have been conducted for each of the eight delivery years spanning 2007/08 through 2014/15. Each auction is held three years prior to the delivery year, with the exception of the first four delivery years when the BRAs were conducted over a compressed period while transitioning to the full three-year forward procurement period after RPM's implementation. Over the first eight auctions, and excluding additions due to territory expansion, total capacity supplies offered have increased by 16.9 UCAP GW while capacity cleared has increased by 11.5 UCAP GW, with most incremental supplies coming from demand response.

With a few exceptions during the first delivery years of RPM, primarily within LDAs, each auction has procured capacity in excess of the procurement target, but with surplus supply in the

unconstrained RTO exceeding the surpluses in the smaller constrained LDAs. Clearing prices have been consistent with these supply-demand fundamentals, producing prices below Net CONE under conditions of excess supply, but above Net CONE in locations of tight supply during the first few delivery years. Prices have also been substantially affected by whether an LDA was modeled as constrained, changes in LDA transmission import limits (CETL), changes in PJM's load forecasts, a substantial growth in demand response, and the EPA's proposed Hazardous Air Pollutant ("HAP") regulation.[7]

1. Resource Adequacy Achieved Through Base Auctions

Cleared quantities relative to target procurement for the RTO and all modeled LDAs are shown in Figure 4. The figure charts cleared capacity relative to the procurement target for each BRA. The black horizontal line at 100% represents the target procurement quantity, with points above indicating procurement above the reliability target, while points below the line indicate procurement below the target. Procurement levels can deviate from the target because RPM is structured to commit higher quantities when offer prices are low and procure lower quantities when offer prices are high.

At the aggregate RTO level, procurement levels exceeded the target in every one of the first eight base residual auctions by 1.2% to 4.7%. These results reflect the surplus supply conditions in the system overall. The RTO-wide surplus dropped between the introduction of RPM (the 2007/08 delivery year) and the 2010/11 delivery year, but then increased again starting in 2011/12 due to factors that included load forecast reductions, the exclusion of Duquesne as load for one year, and a large influx of DR into the auctions (starting with the May 2009 BRA for the 2012/13 delivery year).

Within the LDAs, overall trends in procurement levels have steadily increased relative to reliability targets. While some procurement levels were below reliability targets during the first four delivery years (2007/08 through 2010/11), procurement levels in LDAs universally exceeded reliability targets for the most recent four delivery years (2011/12 through 2014/15). During the first four BRAs, several LDAs including MAAC, EMAAC, SWMAAC, and DPL-South were below the target in some years, with procurement as much as 2.6% below the target for SWMAAC for the 2009/10 delivery year. These deficits reflected the relatively tighter eastern PJM supply conditions that existed at the inception of RPM and, in fact, motivated the need for a locational capacity market. The compressed timing of the initial three auctions also limited the ability of new resources to enter, given the short lead times to delivery. Additionally, DR was not yet widely participating in the forward auctions, opting instead to participate as Interruptible Load for Reliability ("ILR"), which was committed for reliability outside the auctions.[8] In subsequent auctions, conducted a full 3 years before delivery, additional new

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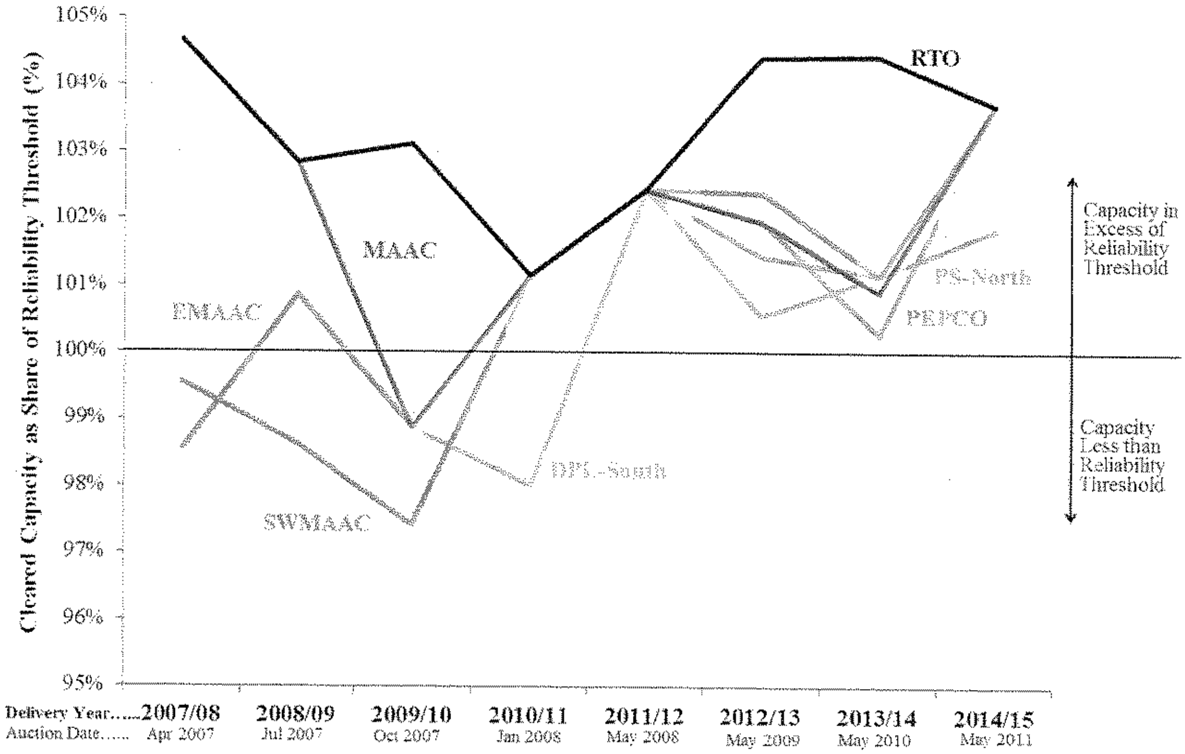
7 The proposed rule will institute emissions limits for coal- and oil-fired generators for mercury, particulate matter as a proxy for other toxic metals, and hydrochloric acid as a proxy for all toxic acid gases. See EPA (2011a-b).

8 The first four BRAs under RPM were conducted within one calendar year between April 2007 and January 2008. This means that the 2007/08 BRA was held two months prior to the delivery year, the 2008/09 BRA was held 1 year prior to delivery, the 2009/10 BRA was held 1.5 years prior to delivery, the 2010/11 BRA was held 2.5 years prior to delivery, and all auctions starting with 2011/12 were held 3 years prior to delivery.

capacity resources entered, and the LDA procurement increased to meet or exceed reliability requirements.

Figure 4
Reliability Margins Clearing in Base Residual Auctions



Sources and Notes:
Reliability threshold defined as the reliability requirement less CETL, less forecast ILR or STRPT.
LDAs that did not price separately are reported here at the reliability margin of the parent LDA or RTO level.
From BRA parameters and results, PJM (2007a-b, 2008a-c, 2009a-e, 2010a-b, 2011b-c).

2. Market Clearing Prices in Base Residual Auctions

Market prices for capacity can be compared to the Net Cost of Net Entry (Net CONE), representing the fixed cost of a new peaking plant net of operating margins from energy and ancillary service revenues. Net CONE is the capacity price that a developer would need to receive *on average* over the life of its asset to earn an adequate return on invested capital.

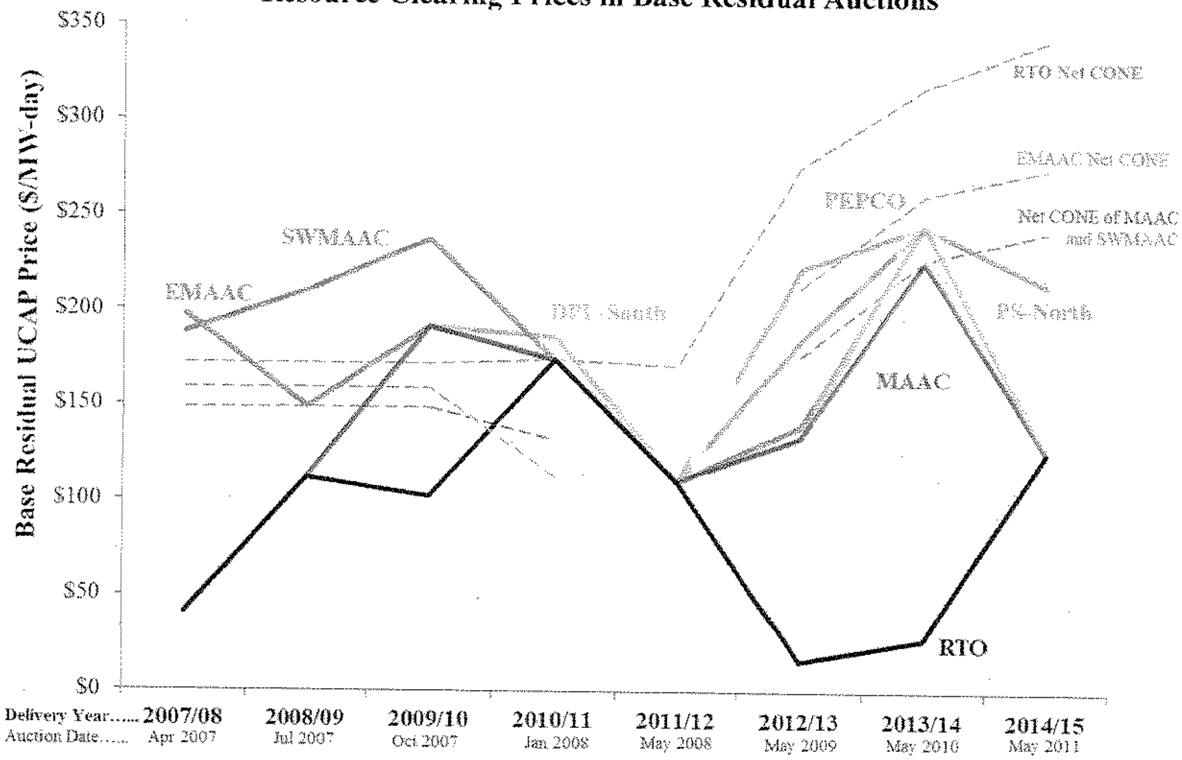
In a well-functioning capacity market, capacity prices will be above Net CONE during shortage conditions when new capacity is needed and below Net CONE during surplus conditions when no new capacity is needed. Such market prices will provide sufficient incentives to attract and retain capacity when new supplies are needed, encourage cost savings by postponing new development, and allow economic retirements when supplies are more than sufficient. This is the desirable pattern that has been observed in RPM auctions, as shown in Figure 5.

Figure 5 and Table 1 summarize RTO and LDA clearing prices for each base residual auction conducted to date. Figure 5 also shows Net CONE for each area in dashed lines. Although the administratively-determined Net CONE calculation may deviate from the true Net CONE faced

by suppliers (as discussed in Section V), it is still a meaningful benchmark for interpreting auction results. The comparison of Figure 5 to Figure 4 confirms that prices have been above Net CONE under conditions of capacity scarcity and below Net CONE under conditions of capacity surplus.

Prices in the unconstrained RTO have been far below Net CONE in most years, reflecting significant excess capacity and the availability of low-cost resources that obviated the need for new generation capacity. Within the LDAs, several of the initial auctions produced prices above Net CONE—in MAAC, EMAAC, SWMAAC, and DPL-South—consistent with the initial resource adequacy deficiencies. In more recent auctions for delivery years 2011/12 through 2014/15, capacity supply conditions have reduced prices in these LDAs to levels below Net CONE. These observations are not surprising given that RPM is constructed to produce this result, with a sloping VRR curve that procures less capacity at higher prices during shortage conditions and more capacity at a lower price during surplus conditions.[9]

Figure 5
Resource Clearing Prices in Base Residual Auctions



Sources and Notes:
Administrative Net CONE shown only for the years when it was calculated for each modeled LDA.
Year 2014/15 price shown reflects the system clearing price applicable for Limited Summer resources.
From PJM (2007a-b, 2008a-c, 2009a-e, 2010a-b, 2011b-c).

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9 There are some exceptions to this outcome caused by the 1% quantity adjustment to point b on the VRR curve, which causes prices to clear slightly above Net CONE under slight surplus procurement conditions of less than (1+IRM+1%)/(1+IRM). This occurred in DPL-South in 2012/13 and in PEPCO in 2013/14. For the formula used to calculate VRR curve points, see PJM (2011d), p. 19.

Table 1
Base Residual Auction Clearing Prices

Year	RTO *($/MW-d)*	MAAC *($/MW-d)*	EMAAC *($/MW-d)*	SWMAAC *($/MW-d)*	DPL-S *($/MW-d)*	PSEG *($/MW-d)*	PS-N *($/MW-d)*	PEPCO *($/MW-d)*	Resource Type
2007/08	$40.80	--	$197.67	$188.54	--	--	--	--	n/a
2008/09	$111.92	--	$148.80	$210.11	--	--	--	--	n/a
2009/10	$102.04	$191.32	$191.30	$237.33	--	--	--	--	n/a
2010/11	$174.29	$174.30	--	$174.30	$186.12	--	--	--	n/a
2011/12	$110.00	--	--	--	--	--	--	--	n/a
2012/13	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73	$185.00	--	n/a
2013/14	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	n/a
2014/15	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	*Limited Summer*
	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	*Extended Summer and Annual*

Sources and Notes:
From BRA results, PJM (2007a, 2008a-c, 2009a, 2009e, 2010b, 2011c).
Prices are reported only for years in which each LDA was modeled under RPM.
MAAC + APS price is listed under MAAC for the 2009/10 delivery year.

In addition to these overall supply and demand conditions, many other factors influenced prices, including the significant growth of DR supply, the economic downturn, new environmental regulations, transmission changes, changes to the RPM market design, and changes in RPM administrative parameters. These factors introduced substantial volatility into the auction prices, with large price changes from one year to the next. We analyzed the major drivers of all price changes for the first eight base auctions by examining offer data, supply curves, administrative planning parameters, and RPM rule changes.

Table 2 summarizes our findings. As documented, supply-side factors explain some of the major changes in base auction prices. Most notably, the costs of meeting EPA's new environmental rules contributed to a price increase of $98/MW-day for the 2014/15 delivery year relative to the previous year.[10] On the other hand, increased DR penetration exerted substantial downward pressure on prices, with the largest impact seen starting with the 2012/13 delivery year, when 8,200 MW of demand resources were first incorporated into the auction, contributing to a $94/MW-day RTO-level price drop relative to the previous year.[11] Modeling multiple demand resource products for the first time in 2014/15 also resulted in a modest price separation of up to $11/MW-day, recognizing the somewhat higher value of Extended Summer and Annual resources. Increases in the supply of other types of resources also contributed to maintaining capacity prices below Net CONE. These other sources of supplies include substantial uprates to existing power plants, increased imports, and reduced exports, as discussed further in Section II.C.

[10] See discussion in Section II.A.3, and EPA (2011a-b).

[11] See Section II.A.3 and PJM (2011d), sections 4.3.5 and 9.3.6.

On the demand side, PJM's peak load forecast is a key driver of PJM prices because it is the primary determinant of the target procurement quantity. Load forecast decreases of 1.7% and 2.8% for the 2012/13 and 2014/15 delivery years (relative to the prior year's peak load forecast for the same delivery years) contributed to price reductions in those years, although in neither case was it the most important driver.[12,13] The initial reduction in load forecasts was caused by the economic downturn. The second reduction in load forecasts was caused primarily by changes in forecasting model coefficients due to revisions in historical economic growth rate data used to estimate those coefficients.[14] For the 2011/12 delivery year, the exclusion of 2.9 GW of peak load from Duquesne contributed to a small reduction in price for one year when the transmission owner had planned to withdraw from PJM.[15] Increases in the administratively-determined Net CONE value also tended to increase prices over time by shifting up the VRR curve, although this trend has not had a large impact in any one year.

Finally, locational price differentials were driven partly by locational differences in supply and demand conditions, with excess capacity in the unconstrained RTO and no (or less) excess supply in the eastern LDAs as discussed above and in in Sections II.C. Additionally, major price changes were caused by whether or not an LDA was modeled as being constrained and how much capacity (CETL) could be imported into the LDA. Prior to a rule change for the 2012/13 delivery year, fewer LDAs were modeled, resulting in a lack of locational price separation during some years that would have price-separated under current rules.[16] For example, the MAAC LDA was not modeled for 2007/08 and 2008/09 and no LDAs were modeled for 2011/12. The administratively-determined Capacity Emergency Transfer Limit ("CETL"), which represents the maximum capacity import capability for each LDA, also significantly affected prices. In particular, CETL decreases for the 2013/14 delivery year were a major cause of high prices in the LDAs, while CETL increases for 2008/09 and 2014/15 were a major cause of price reductions.[17]

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12 For 2012/13, the most important price-depressing factor was the integration of a large amount of demand resources. For 2014/15, a CETL increase and load forecast reduction both contributed to a price decrease in the LDAs; in the RTO, the price-increasing impact of EPA HAP regulations overwhelmed the price reduction effect of reduced load forecasts.

13 Reported load forecast reductions represent summer coincident peak load forecasts including Duquesne, but excluding ATSI and DEOK. The RTO summer coincident peak load forecast for the 2012/13 delivery year dropped from 147,183 to 144,613 MW between the forecasts prepared in 2008 and 2009; the 2014/15 delivery year forecast dropped from 149,572 MW to 145,404 MW between the forecasts prepared in 2010 and 2011. See PJM (2008d), p. 46; (2009f), p. 50; (2010e), p. 53; (2011g), p. 54.

14 These economic growth rates were revised by the Bureau of Economic Analysis. Confirmed via personal communication with PJM staff. , See Section VI.B for a more detailed discussion of load forecasting.

15 See PJM (2009g), p. 1.

16 Prior to the auction for the 2012/13 delivery year, LDAs were modeled only if their Capacity Emergency Transfer Objective ("CETO") was ≤ 1.05 CETL. Starting with the 2012/13 delivery year more LDAs were modeled, including: (1) MAAC, SWMAAC, and EMAAC which will always be modeled; (2) LDAs with CETO ≤ 1.15 CETL; (3) LDAs that have price separated in any of the three previous BRAs; and (4) any LDAs that PJM expects may price separate. See PJM (2011d), pp. 11-12.

17 See Section VI.A for further discussion of CETL uncertainty and recommended mitigation measures.

Table 2
Summary of Major BRA Price Shifts and Causes

Year	Location	Causes of Major Price Changes from Previous Year
2007/08	*RTO* -	Price of $41/MW-day is far below Net CONE, reflecting a capacity surplus.
	EMAAC and SWMAAC -	Prices near $200/MW-day are above Net CONE, reflecting tight supply.
2008/09	*RTO* -	$71/MW-day increase caused by relaxed EMAAC transmission constraint, modest demand growth, and a steep supply curve.
	EMAAC -	$49/MW-day drop caused by 2,085 MW CETL increase.
2009/10	*MAAC+APS* -	LDA is first modeled with prices $89/MW-day above the RTO. If MAAC had been modeled in earlier years, it likely would have had similarly high or higher prices.
	SWMAAC -	Clears slightly below the LDA price cap due to short supply and a steep supply curve.
2010/11	*RTO* -	Modest increases in demand, coupled with somewhat smaller increases in supply and a steep supply curve, cause RTO prices to increase by $72/MW-day.
	SWMAAC -	63/MW-day drop to the parent LDA price caused by lower offer prices for several existing generation supplies relative to 2009/10 offers, nearly 300 MW in generation uprates, a 276 MW increase in CETL, and a 29% reduction in SWMAAC Net CONE which reduced the VRR curve.
2011/12	*RTO* -	Exclusion of Duquesne load for one year causes some price suppression.
	LDAs -	No LDAs are modeled, preventing price separation.
2012/13	*RTO and LDAs* -	Large 8,200 MW influx of previously unoffered demand response is incorporated into the BRA due to a rule change in treatment from ILR to DR; this and a peak load forecast reduction cause a large $94/MW-day price drop in the RTO.
	LDAs -	Rule change permanently causes more LDAs to be modeled, allowing price separation.
2013/14	*LDAs* -	Large CETL reductions of almost 2,000 MW in MAAC and EMAAC and 675 MW in SWMAAC substantially restrict low-cost imports to the LDAs. Prices increase by $93/MW-day in MAAC and SWMAAC and by $205/MW-day in EMAAC.
2014/15	*RTO* -	Prices increase by $98/MW-day due primarily to high bids and excused capacity from coal units related to EPA HAP MACT regulations. More than 6,200 MW less existing generation clears in the unconstrained RTO (excluding ATSI, DEOK, and imports), replaced by a large increase in cleared demand resources.
	LDAs -	2.8% load forecast drop and 1,100 to 1,200 MW increase in CETL in MAAC, EMAAC, and SWMAAC create a supply surplus relative to previous year in eastern LDAs.
	PSEG-North -	Price drop of $31/MW-day is not as substantial as in other LDAs, and is limited by transmission constraints, which are near their historical levels.
	Extended Summer and Annual -	Resource types are modeled separately for the first time, leading to an $11/MW-day price premium for extended summer and annual resources in LDAs and a smaller premium less than $1/MW-day in the unconstrained RTO.

Sources and Notes:
Causes of price changes determined from analysis of auction bid data, supply curves, demand curves, and parameters.
From BRA parameters, results, and bid data, PJM (2007a-b, 2008a-c, 2009a-e, 2010a-b, 2011a-c).

3. Resources Offered and Cleared in the Base Auctions

a. *Aggregate Results for the Entire PJM RTO*

The total amount of capacity offered in the RTO has increased substantially since the start of RPM, as summarized in Table 3. The table reports total quantities of unforced capacity (UCAP) offered, cleared, and uncleared in the eight base auctions conducted to date for the entire RTO. The tables are non-cumulative with respect to the identification of new generation offers, in that any new generation that clears one BRA is reported as existing generation for all subsequent BRAs.[18] Total offers have increased by 29.6 GW (from 131 to 160 GW) while total capacity cleared has increased by 20.6 GW (from 129 to 150 GW). However, nearly half of that increase is due to PJM's expansion that integrated FirstEnergy (through its subsidiary American Transmission Systems, Inc. or "ATSI") into the BRA starting with the 2013/14 delivery year.[19] Duke Energy Ohio/Kentucky ("DEOK") also began its integration into RPM starting with the 2014/15 BRA, but so far has had little impact on auction clearing quantities.[20]

For the RTO (excluding ATSI and DEOK), capacity offers increased by 16.9 GW while capacity cleared increased by 11.5 GW. Large increases came from new DR and energy efficiency (EE) resources. Cleared quantities of DR and EE increased from just 0.1 GW at the start of RPM to 13.9 GW for the 2014/15 delivery year. DR and EE now amount to 9.9% of total cleared supplies. Cleared imports also increased from 1.6 to 4.0 GW or to 2.9% of cleared supplies.[21]

For PJM-internal generation supplies (including both new and existing resources), total offered quantities decreased by 0.7 GW while total cleared quantities decreased by 4.7 GW. These reductions were almost entirely caused in response to EPA's HAP regulation, which will substantially tighten emissions standards on mercury, other toxic metals, and acid gases. In anticipation of this regulation and the need for environmental upgrades by 2015 or 2016, a large number of coal units of FRR entities were excused from offering into the 2014/15 auction or failed to clear in the BRA after offering at higher levels reflecting the costs of upgrades (and some cleared).[22]

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18 Also note that the same unit may be listed as new capacity under more than one BRA if the new unit failed to clear the first time it was offered and was offered later in a subsequent BRA. This approach to summarizing new generation is consistent with the definition of new generation as used for market monitoring and mitigation purposes, see PJM (2011d), p. 65. Section II.C contains a cumulative account of capacity additions and reductions over time.

19 ATSI was integrated into the PJM energy market on June 1, 2011, but as a transitional measure for resource adequacy purposes it was not fully integrated into RPM auctions until the 2013/14 delivery year. For the 2011/12 and 2012/13 delivery years, resource adequacy in the zone was assured through transitional FRR plans for which capacity was procured in separate integration auctions. Only small amounts of capacity from ATSI were offered into the BRA. See PJM (2010c) and (2011e).

20 See PJM (2010d), pp. 25-26.

21 These are gross imports cleared in the base auctions without considering exports.

22 The exact date that most generators will be required to either shut down or operate with additional controls is not yet determined. The EPA is required under consent decree to issue a final rulemaking by November 16, 2011, after which generators will have three years to comply, with the possibility of an additional year's extension for compliance if they can show that the additional time is needed to install

Continued on next page

Table 3
RTO Summary of BRA Offered and Cleared Quantities
(UCAP MW)

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Total RTO								
Offered	130,844	131,881	133,551	133,093	137,720	145,373	160,898	160,486
Cleared	129,409	129,598	132,232	132,190	132,222	136,144	152,743	149,975
Uncleared	1,435	2,283	1,319	902	5,499	9,230	8,155	10,512
RTO Excluding ATSI and DEOK								
Offered	**130,844**	**131,881**	**133,551**	**133,093**	**137,057**	**145,373**	**147,563**	**147,724**
Existing Internal Generation	129,080	129,408	130,467	129,984	131,013	131,095	131,205	127,418
Existing Imported Generation	1,621	1,667	1,708	1,734	1,750	2,336	3,254	4,031
New Generation	16	89	439	407	2,642	1,442	783	1,016
Demand Response	128	716	937	968	1,652	9,848	11,568	14,430
Energy Efficiency	-	-	-	-	-	653	754	829
Cleared	**129,409**	**129,598**	**132,232**	**132,190**	**132,222**	**136,144**	**142,047**	**140,957**
Existing Internal Generation	127,645	127,346	129,370	129,237	126,964	125,347	128,461	122,603
Existing Imported Generation	1,621	1,626	1,669	1,726	1,748	2,336	3,254	4,031
New Generation	16	89	300	288	2,144	845	769	395
Demand Response	128	536	893	939	1,365	7,047	8,888	13,108
Energy Efficiency	-	-	-	-	-	569	676	819
Uncleared	**1,435**	**2,283**	**1,319**	**902**	**4,836**	**9,230**	**5,516**	**6,767**
Existing Internal Generation	1,434	2,062	1,098	747	4,049	5,748	2,744	4,815
Existing Imported Generation	0	41	39	8	2	-	-	-
New Generation	-	-	139	119	497	598	14	621
Demand Response	-	180	44	29	288	2,800	2,680	1,322
Energy Efficiency	-	-	-	-	-	84	77	10

Sources and Notes:
Calculated from BRA bid data, PJM (2011a).
New generation includes newly build internal and imported generation that has not cleared any previous auction.
Uprates are treated as existing generation.

It is important to note that every auction attracted more offers than were needed, resulting in some capacity offers not clearing. The uncleared capacity *could* have been procured at higher prices if market conditions were tighter and the capacity was needed. The amount of uncleared capacity was quite low in the initial auctions but has been between 3.7% and 6.8% of cleared supplies in the most recent four BRAs. The increase in uncleared capacity coincided with the first year of full three-year forward procurement and exclusion of Duquesne load in 2011/12 (which reduced demand) and the full integration of demand resources into RPM auctions starting in 2012/13.[23] It is also important to evaluate the availability of cleared and uncleared offers for new generation supplies that have been attracted into the auctions. Offers for new generation ranged from 407 MW to 2,642 MW in each auction starting with 2009/10. Of the total 6,834

Continued from previous page
controls, see EPA (2011b), pp. 24986, 25054. Auction impacts from analysis of 2014/15 FRR-excused and BRA biding data as well as PJM's supplemental 2014/15 BRA report, PJM (2011a) and (2011f).

23 Duquesne's reliability requirement of approximately 3 GW was excluded from the BRA in 2011/12, while supply of approximately the same amount was retained and offered in the BRA, see Monitoring Analytics (2008), pp. 10-12. Prior to the 2012/13 delivery year, demand-side resources could certify as ILR immediately prior to the delivery period and receive payments based on auction clearing prices. Starting with 2012/13, all demand-side resources must be committed under an RPM auction or through a bilateral replacement transaction to receive capacity payments, see PJM (2011d), sections 4.3.5 and 9.3.6.

MW of new generation offered into all base auctions conducted to date, 4,847 MW or 71% have cleared.[24]

b. *Resources Offered and Cleared within the LDAs*

Some stakeholders raised concerns that the RPM auctions are not attracting new resources to ensure reliability within the LDAs, particularly the smaller LDAs. Our analysis of the data shows that is not the case. RPM auctions attracted offers and cleared adequate resources even in the smaller LDAs, except in some of the earlier auctions as discussed earlier and shown in Table 4. Table 4 summarizes the quantity of cleared and uncleared capacity by LDA for all currently modeled LDAs. Note, however, that previous BRAs did not model the same set of LDAs.

Within MAAC, which is the largest of the LDAs and contains all of the smaller LDAs, cleared supply and uncleared potential supply have been robust.

- Penetration of demand-side resources has been higher in MAAC than in the greater RTO, having increased from 0.1% to 11.1% of total cleared resources under RPM.
- Internal generation supplies in MAAC have been relatively constant over the first eight auctions (while internal generation in the unconstrained RTO decreased). Offered generation in MAAC has increased by 1,297 MW, although the total amount cleared generation has decreased by 671 MW or 1% of cleared resources. Unlike the greater RTO, the MAAC region has been relatively less affected by the proposed EPA regulation. Between the auctions for the 2013/14 and 2014/15 delivery years, MAAC had a 1,877 MW or 3.0% decrease in cleared generation (compared to 4.8% in the RTO overall).
- In addition to the resources that cleared in MAAC, another 0.7% to 6.5% of uncleared offers were available that could have been procured at higher prices had they been needed for reliability. Offers for new generation in MAAC have also been substantial, at 3,512 MW of BRA offers, of which 1,798 MW or 51% have cleared. These offers ranged from 110 MW to 1,038 MW in each year since 2009/10. In the smaller LDAs, the changes in supplies offered and cleared have been similar to MAAC overall although varying by location. In particular, penetration of DR and EE has been high in most LDAs, and by 2014/15 these resources contributed a large fraction of cleared internal BRA supply, ranging from 8.9% for EMAAC to 21.5% in SWMAAC.[25]

Most LDAs, even the smallest LDAs, had substantial quantities of uncleared offers for additional capacity that could have been procured at a higher price had they been needed for reliability. In some years, the smallest LDAs—including PEPCO, PSEG, PSEG-North, and DPL-South—did not have any uncleared offers, but almost all of these events occurred in the initial auctions when

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[24] Note that in some cases the uncleared offers may represent the same unit that failed to clear and subsequently re-offered. However, cleared MW as reported here would in no cases represent the same unit twice as once the unit clears in one RPM auction it is no longer considered a new unit. Cleared or uncleared offers for new capacity in the incremental auctions are not reported in this section of the report.

[25] This does not mean DR and EE represent the same large fraction of total resources available to these LDAs as the number does not account for the capacity resources available through import capability in each location.

the regions were not deemed constrained and were not modeled in RPM.[26] Among modeled LDAs, the only BRA showing no uncleared capacity was in DPL-South in 2013/14, a year in which the cleared capacity had already exceeded the procurement target.[27] We observed in none of the LDAs any potentially concerning pattern of persistently low offer quantities, and it appears that substantially higher quantities of supply, if needed, could have been procured in every LDA at higher prices.

New generation offers have been unevenly distributed, although the data is difficult to interpret in the smallest LDAs, including DPL-South, where a single new plant would be sufficient to meet load growth for a decade.[28]

- EMAAC and its subregions—PSEG, PSEG-North, and DPL-South—have all attracted substantial offers for new generation equivalent to between 8% and 31% of total cleared internal resources within these LDAs. Just over half of these offers cleared due to relatively low prices compared to the cost of new entry and sufficient supply, as discussed earlier.
- In SWMAAC, lower quantities of new capacity were offered in the BRAs, but still equivalent to 4.2% of cleared resources, and almost none of this capacity has cleared.
- The PEPCO subregion has attracted only a negligible quantity of offers for new generation capacity to date. This lack of offers for new generation in PEPCO is a potential concern that may be caused by higher development costs and siting challenges. However, the lack of offers likely is also related to the relatively smaller size of the LDA and developers' understanding that the subregion already has sufficient supply, including from high levels of new demand response, reductions in load forecast, and increases in import capability.[29]

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[26] The history of which LDAs were modeled in which year can be seen in Table 1, which indicates unmodeled LDAs as dashes.

[27] As seen in Figure 4.

[28] Based on 2,369 MW projected DPL-South peak load in 2014 and 2,637 MW projected peak load in 2024, assuming that DPL-South peak load grows at the same rate as DPL overall. The 268 MW of load growth may translate into a 341 MW increase in the UCAP LDA reliability requirement if it increases proportionally. This increase is smaller than the approximate 650 UCAP MW that may be contributed by a new combined cycle generator as indicated by three recent projects proposed in New Jersey. See PJM (2011b) and (2011g), p. 54; Levitan (2011), p. 2.

[29] For example, between the 2013/14 and 2014/15 BRAs, the need for internal PEPCO resources was reduced from 4,959 to 3,345 UCAP MW or by 33%. Contributing factors to this change were a 491 MW reduction in the reliability requirement and a 1,123 MW increase in CETL. See PJM (2010a, 2011b).

Table 4
LDA Summary of BRA Offered and Cleared
(UCAP MW)

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
MAAC								
Cleared	**60,476**	**60,707**	**63,010**	**63,328**	**61,603**	**65,465**	**67,640**	**67,176**
Existing Generation	60,395	60,190	62,158	62,399	60,018	60,299	61,061	59,487
New Generation	16	40	110	21	540	262	556	253
DR and EE	66	478	743	908	1,045	4,904	6,023	7,436
Uncleared	**557**	**1,404**	**432**	**502**	**3,979**	**2,830**	**698**	**3,709**
Existing Generation	557	1,224	427	355	3,325	2,054	684	1,904
New Generation	-	-	-	119	497	463	14	621
DR and EE	-	180	6	29	156	312	-	1,185
EMAAC								
Cleared	**30,782**	**30,214**	**31,622**	**30,787**	**29,365**	**31,080**	**32,835**	**32,554**
Existing Generation	30,722	30,045	31,157	30,474	28,598	29,260	29,856	29,592
New Generation	16	-	93	6	535	162	494	74
DR and EE	45	169	372	306	231	1,658	2,485	2,888
Uncleared	**29**	**1,148**	**34**	**431**	**2,670**	**1,902**	**172**	**1,966**
Existing Generation	29	973	29	300	2,317	1,526	158	741
New Generation	-	-	-	119	277	223	14	621
DR and EE	-	175	4	12	76	153	-	604
SWMAAC								
Cleared	**10,201**	**10,621**	**9,915**	**10,873**	**10,780**	**11,595**	**11,242**	**11,124**
Existing Generation	10,182	10,312	9,558	10,354	10,039	9,661	9,480	8,726
New Generation	-	-	-	-	-	-	2	3
DR and EE	20	309	356	519	741	1,933	1,760	2,396
Uncleared	-	**5**	**397**	**55**	**871**	**801**	**526**	**1,334**
Existing Generation	-	-	397	55	612	477	526	1,093
New Generation	-	-	-	-	221	240	-	-
DR and EE	-	5	-	-	39	85	-	240
PSEG								
Cleared	**6,734**	**6,734**	**6,957**	**6,938**	**6,729**	**7,194**	**8,019**	**7,583**
Generation	6,734	6,681	6,856	6,862	6,699	6,731	6,893	6,614
DR and EE	-	52	101	75	31	463	1,127	969
Uncleared	-	**150**	-	**282**	**674**	**237**	**14**	**601**
Generation	-	102	-	278	655	223	14	423
DR and EE	-	48	-	4	19	14	-	178
PEPCO								
Cleared	**5,019**	**5,125**	**4,686**	**5,498**	**5,664**	**5,357**	**4,792**	**5,615**
Generation	5,014	5,093	4,621	5,464	5,519	4,840	4,209	4,679
DR and EE	5	32	65	33	145	517	583	936
Uncleared	-	**2**	**378**	-	**6**	**24**	**497**	**261**
Generation	-	-	378	-	-	-	497	131
DR and EE	-	2	-	-	6	24	-	130
PSEG-North								
Cleared	**3,737**	**3,734**	**3,767**	**3,672**	**3,640**	**3,550**	**4,159**	**3,818**
Generation	3,737	3,734	3,767	3,672	3,640	3,453	3,631	3,374
DR and EE	-	-	-	-	-	97	528	443
Uncleared	-	**22**	-	**199**	**369**	**223**	**14**	**352**
Generation	-	22	-	199	369	223	14	299
DR and EE	-	-	-	-	-	-	-	53
DPL-South								
Cleared	**1,583**	**1,587**	**1,587**	**1,520**	**1,454**	**1,323**	**1,612**	**1,439**
Generation	1,575	1,587	1,587	1,505	1,428	1,177	1,465	1,213
DR and EE	8	-	-	15	26	146	148	226
Uncleared	-	-	-	**26**	**32**	**257**	-	**161**
Generation	-	-	-	26	32	257	-	120
DR and EE	-	-	-	1	-	-	-	41

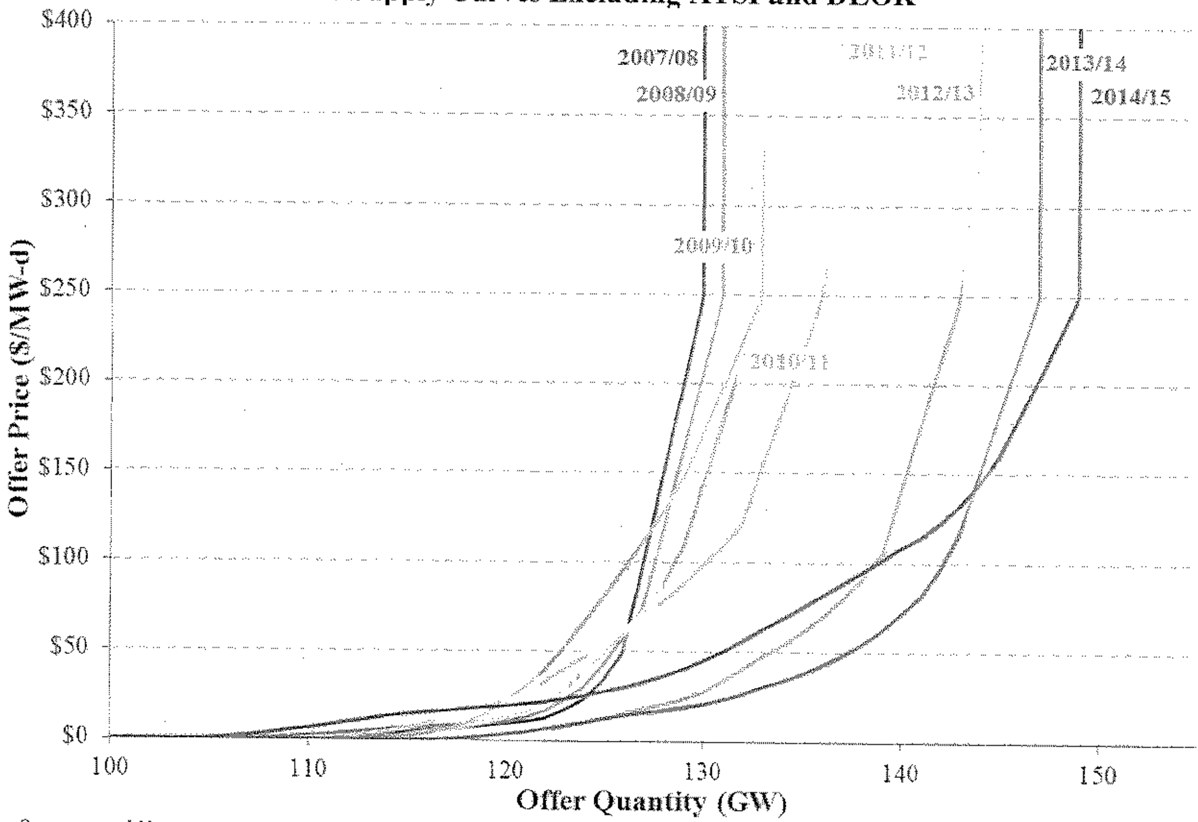
Sources and Notes:
Calculated from BRA bid data supplied by PJM (2011a). Uprates are treated as existing generation.
New and existing generation are aggregated in the smaller LDAs to avoid revealing market-sensitive data.

4. BRA Supply Curves

The previous section described the quantities of resources offered and cleared in the auctions, but did not address the prices at which suppliers offered their resources. In fact, offers from many existing and new resources have changed substantially over time, affecting supply curve shapes and thus auction prices and quantities cleared. This subsection analyzes the shapes of the supply curves and the changes in market rules and fundamentals that have caused them.

Our analysis is based primarily on the mitigated supply curves in each BRA conducted to date, although we have also reviewed the individual resource offers and report observations at an aggregate level. Figure 6 shows the (smoothed) mitigated supply curves offered into the BRA for the delivery years 2007/08 through 2014/15, excluding capacity from ATSI and DEOK to make the curves comparable. The 2014/15 supply curve represents the total system supply of all newly-introduced resource types.[30]

Figure 6
BRA Supply Curves Excluding ATSI and DEOK



Sources and Notes:
Curves exclude supply from ATSI and DEOK zones. Smoothed to mask confidential market data.
From PJM supplier bidding data, PJM (2011a).

[30] The curve includes all Annual, Extended Summer, and Limited resources, but does not double-count capacity that submitted linked offers for multiple product types.

Our primary observations, which we explain in greater detail below, are as follows:

- *Supply curves with decreasing slopes through 2011/12*: Overall, the BRA offer curves have become progressively more gradual over time, ascending from zero through many mid-range offers to higher offers. These flatter curves help stabilize auction prices, all else being equal. Offer curves became more gradual as the forward period increased progressively from 2 months to 3 years during the forward-procurement transition from 2007/08 through 2011/12, allowing resource investments to be offered contingent on auction prices.

- *The full integration of DR starting in 2012/13.* Fully integrating DR into the auctions (instead of procuring it outside of the auctions as ILR) significantly expanded the offer curves. At first, existing DR was mitigated to zero. DR was unmitigated starting with the 2013/14 auction, which stretched out the mid-range of the curve.

- *Incorporation of environmental retrofit costs, especially for 2014/15*: the 2014/15 offer curve had the most gradual shape yet, with many coal generators that were previously offering at zero now offering at a range of non-zero prices related to their expected costs of complying with EPA regulation.

- *The introduction of multiple DR products, starting in 2014/15*: as expected, the offers for higher-value Annual and Extended Summer products are less plentiful and occur at higher prices than Limited DR. The Extended Summary and Annual supply curves are very similar to each other.

Supply Curves with Decreasing Slopes through 2011/12. The decreasing slopes of the supply curves for the 2007/08 through 2011/12 delivery years in large part reflect the fact that the base auctions were held with an increasing forward procurement periods of 2 months, 1 year, 1.5 years, 2.5 years, and 3 years to delivery. These first five auctions were held within a single year—between April 2007 and May 2008—as part of the transition period. The comparison of their supply curves shows a progressive change in supply. With each successive auction, substantially more supplies were offered and the supply curve became more gradual. We attribute these changes to the increasing forward period. Without sufficient lead-time to develop new resources, as was the case for the first BRA in 2007/08, supply curves will be steep as nearly all existing resources offer at (or are mitigated to) a price of zero. A forward period of several years will make the supply curve more gradual, as many investment decisions can be made contingent on the auction clearing price. New supplies such as uprates to existing or new generation can offer in to compete with capacity of existing supplies. Further, existing resources that require major capital expenditures to maintain operational can offer at a price commensurate with costs, and then make the upgrade contingent on clearing. Overall, the more gradual supply curve indicates that the three-year forward period has contributed to increased efficiency and competition among resources. It also contributes to greater stability in clearing prices.

The Full Integration of DR Starting in 2012/13. The 2012/13 supply curve shows a large increase in the quantity of offers due to the influx of DR into the auctions. In 2012/13, existing DR suppliers were required to offer into the capacity market at a mitigated offer price of zero.[31]

[31] See FERC (2009), pp. 10-11.

Starting with 2013/14, offer prices for DR were unmitigated and these suppliers offered over a range of prices.[32] The rapid growth of low-cost DR in the last several auctions contributed to lower prices, which has been a cause for concern among generation owners. We expect that the price-reducing effect of DR will not continue indefinitely, as continued DR growth will result in greater curtailment frequencies and more costly DR resources in the future. In fact, we observed that, starting with the auction for the 2013/14 delivery year, DR suppliers offered over a range of prices, which contributed to a substantially more gradual supply curve. These DR offer levels are likely related to opportunity costs of retail customers and expectations regarding future curtailment levels, as well as a range of customer characteristics. We expect that DR offer curves will eventually stabilize, and cleared amounts will increase or decrease with capacity prices, thereby creating more price stability in RPM.

Incorporation of Environmental Retrofit Costs, Especially for 2014/15. The 2014/15 supply curve has fewer offers at zero prices. Many existing generation resources were offered at non-zero levels, mostly due to coal units offering at prices related to their costs of environmental upgrades to meet EPA regulations. While the total system-wide costs of these upgrades are substantial, and installing them all simultaneously will be a challenge, we note that the three-year forward period of RPM has greatly increased the transparency of this process. Because coal units have bid into the capacity market over a range of prices consistent with their expected costs, the forward capacity auction has effectively prioritized the lowest-cost upgrades. Coal units requiring more expensive upgrades, presumably on older and less efficient plants, did not clear and will likely retire, thereby also reducing the current capacity surplus.

The Introduction of Multiple DR Products, Starting in 2014/15. Given the greater capacity obligations of Extended Summer and Annual resources, the supply curves for these resources are at a higher price and have fewer offers available than Limited Resources. There is a large difference in the quantity of Limited and Extended Summer supplies, and it has been suggested that some Limited Summer resources did not have sufficient time to revise their contracts to allow them to offer an Extended Summer product. We also note the possibly surprising fact that the Extended Summer and Annual supply curves are very similar to each other, implying that the large majority of these non-Limited resources may have annual capability. The similarity between the Annual and Extended Summer supply curves also indicates that DR suppliers may not expect substantially more curtailment for Annual resources under current market conditions. In the future, as DR penetration reaches a level sustainable in the long term, we expect that curtailment frequencies will increase and, as a result, may be quite different for Limited, Extended Summer, and Annual DR products. Under those conditions, we would expect a larger discrepancy between the supply curves for the varying obligation levels.

B. Incremental Auction Results

A small portion of capacity is procured through the incremental auctions. No stakeholder group raised concerns about the incremental auctions. However, these auctions play an essential role in RPM's ability to meet resource adequacy requirements efficiently. The incremental auctions are used to procure 2.5% (starting with the 2012/13 delivery year) of the expected total capacity obligation for the delivery year and are used to procure any unexpected needs that emerge

[32] See PJM (2011d), p. 65.

between the BRA and the delivery year. Incremental auctions help short-term resources compete without assuming the risks of three-year forward commitments. They also help reduce the risk of other suppliers assuming forward commitments by providing opportunities to buy (and sell) replacement capacity if needed.

This section explains the timing of incremental auctions, documents rules changes, analyzes offers and buy bids, and reports auction prices. We find that IA prices prior to the auction redesign were consistently below the BRA prices and that the prior IA design created an uneconomic incentive for DR resources to bid just above the BRA price. Results after the auction redesign in 2012/13 show that the new design produces results that are more efficient and consistent with market conditions. However, with only two auctions conducted to date, there is still insufficient evidence to fully evaluate the new IA design. We also find that, while many buy bids in incremental auctions were used to replace existing capacity commitments, a substantial number of low-priced buy bids were also submitted pre-emptively to procure extra capacity that can be used to replace potential future deficiencies.

1. Incremental Auction Mechanics and Redesign in 2012/13

Incremental auctions are held two years, one year, and several months prior to the delivery year.[33] For the first four delivery years of RPM, the IAs were primarily a capacity aftermarket in which suppliers could adjust their capacity commitments for changes to their resource ratings or costs. In these early years, PJM did not procure any net capacity from the first or third IAs for resource adequacy, although a load forecast increase would have triggered a second IA for incremental procurement.[34]

Third incremental auctions have been held for the 2008/09 through 2011/12 delivery years. First IAs have been conducted for 2011/12 and 2012/13. Several early delivery years did not have a full set of IAs due to the compressed forward period when RPM was phased in and because second incremental auctions would only have been held in the case of a load forecast increase.

Starting with the 2012/13 delivery year, a new incremental auction design was implemented. The first, second, and third IAs now have a Short-Term Resource Procurement Target ("STRPT") of 0.5%, 0.5%, and 1.5% respectively. The redesign also fully incorporated DR resources into the capacity auctions instead of awarding auction-based prices to DR certified as Interruptible Load for Reliability (ILR) immediately prior to the delivery year. Additionally, the new incremental auction design includes the uncleared portion of the VRR curve and adjusts the demand for updates in the load forecast and transmission limits in some cases.[35] Suppliers can use these incremental auctions to adjust or replace their capacity obligations.

[33] Specifically, the first IA is held 20 months prior to delivery, the second IA is held 10 months prior to delivery and the third IA is held 3 months prior to delivery. A conditional IA may also be held if additional capacity is needed due to a delay in a backbone transmission upgrade. See PJM (2011d), pp. 69-72.

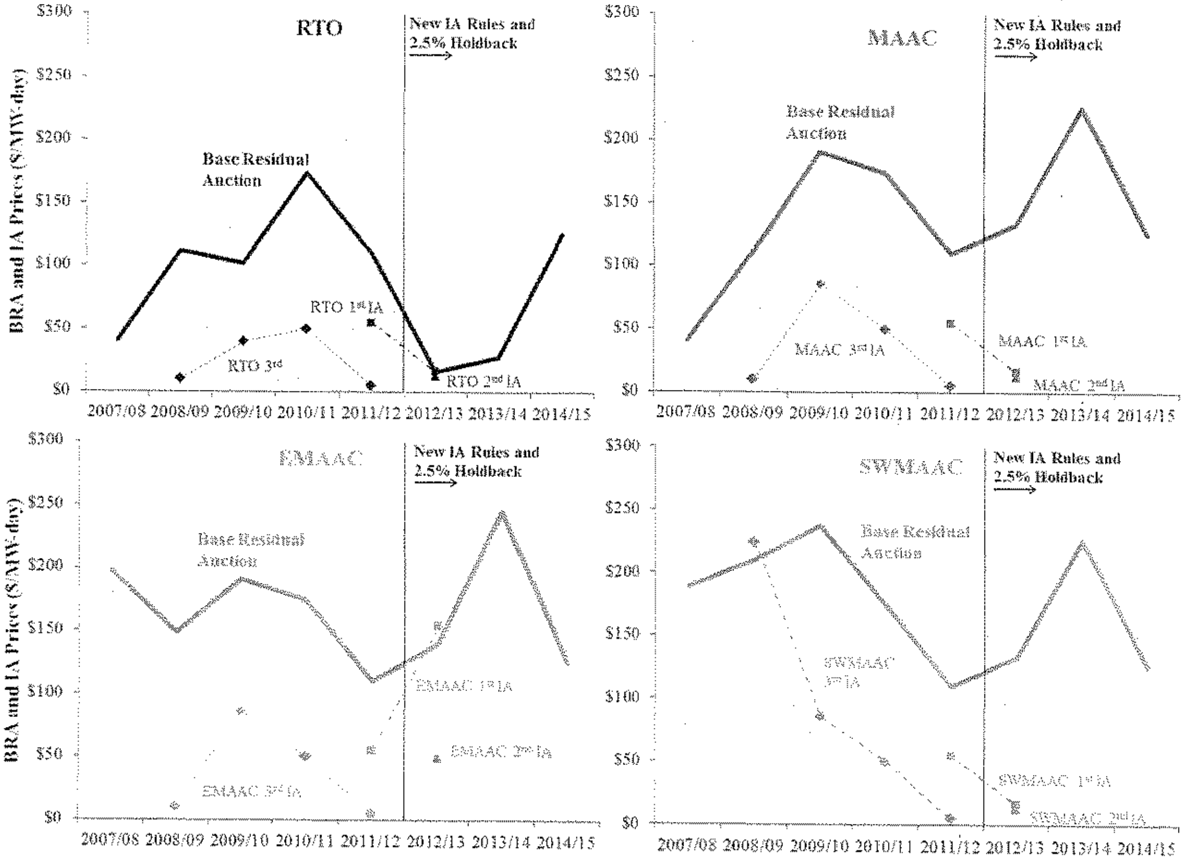
[34] No second IA was ever held for this reason. See *Id.*, p. 72.

[35] See *Id.*, pp. 20-21.

2. Incremental Auction Clearing Prices

Clearing prices in the IAs are summarized in Figure 7 for the RTO and the largest LDAs. (Table 5 shows prices for all locations.) Figure 7 shows BRA prices as a solid line with incremental auction prices shown as dashed lines.

Figure 7
Incremental Auction Clearing Prices



Sources and Notes:
Year 2014/15 BRA clearing prices reflect resource clearing prices without an Annual or Extended Summer price adder.
From BRA and IA results, see PJM (2007a, 2008a-c,e, 2009a,e,h-i, 2010b,f,g, 2011c,g).

As Figure 7 shows, incremental auction prices under the initial design were persistently and substantially below BRA prices—on average $90/MW-day lower in the RTO and on average $115/MW-day lower in MAAC. The only exception occurred in SWMAAC in the third incremental auction for the 2008/09 due to tight supply conditions. Less experience exists to date for the new IA design. However, Figure 7 shows that prices in the first IA for the 2012/13 delivery are very close to BRA prices in the RTO and EMAAC, but much lower than BRA prices in MAAC and SWMAAC.

Table 5
Incremental Auction Clearing Prices

Year	Auction	RTO (*$/MW-d*)	MAAC (*$/MW-d*)	EMAAC (*$/MW-d*)	SWMAAC (*$/MW-d*)	DPL-S (*$/MW-d*)	PSEG (*$/MW-d*)	PS-N (*$/MW-d*)	PEPCO (*$/MW-d*)
2007/08	BRA	$40.80	--	$197.67	$188.54	--	--	--	--
2008/09	BRA	$111.92	--	$148.80	$210.11	--	--	--	--
	3rd IA	$10.00	--	$10.00	$223.85	--	--	--	--
2009/10	BRA	$102.04	$191.32	$191.30	$237.33	--	--	--	--
	3rd IA	$40.00	$86.00	$86.00	$86.00	--	--	--	--
2010/11	BRA	$174.29	$174.30	--	$174.30	$186.12	--	--	--
	3rd IA	$50.00	$50.00	--	$50.00	$50.00	--	--	--
2011/12	BRA	$110.00	--	--	--	--	--	--	--
	1st IA	$55.00	--	--	--	--	--	--	--
	3rd IA	$5.00	--	--	--	--	--	--	--
2.5% Holdback Introduced and New Incremental Auction Design is Implemented									
2012/13	BRA	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73	$185.00	--
	1st IA	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	--
	2nd IA	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	--
2013/14	BRA	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14
2014/15	BRA	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47

Sources and Notes:
From BRA and IA results, see PJM (2007a, 2008a-c,e, 2009a,e,h-i, 2010b,f,g, 2011c,g).
Prices are reported only for years in which each LDA was modeled under RPM.
MAAC + APS price is listed under MAAC for delivery Year 2009/10.

To determine the drivers of incremental auction prices and the price changes between the BRA and the IAs, we examined supply and demand offer data for each of these auctions. A detailed explanation of these price drivers is presented in Table 6. Under the new design, prices in MAAC and SWMAAC were much lower than BRA prices because the load forecast for the delivery year decreased in MAAC. The EMAAC price did not decrease despite a reduced load forecast because of a delay of the Susquehanna-Roseland transmission line, which required substantial incremental capacity procurement.[36] Prices in the second IA for 2012/13 were driven by a reduction in the load forecast in most locations, resulting in a small reduction of prices in the RTO, MAAC, and SWMAAC relative to the already low first IA price, and a large $105/MW-day reduction in EMAAC and its sub-LDAs. These price changes under the new IA design are consistent with the changes in capacity requirements experienced during the period between when the BRA and IA were conducted.

Under the prior incremental auction design, IA prices were consistently far below clearing prices in the BRAs. Offer prices and quantities of generation supply were the primary driver of these price reductions. During the incremental auctions for the 2009/10 and 2010/11 delivery years, a substantial amount of capacity uprates offering at low prices contributed lower-priced supply curves in the IAs. In most other IAs, less existing generation capacity was offered than had

[36] See PJM (2010h).

previously not cleared in the BRAs, but some of the resources that did not clear in the BRA dropped their offer prices to zero or near zero. This change in offer price behavior for some generators, combined with a reduction in offer quantities, resulted in IA supply curves that were relatively steep in some cases. Resulting IA prices were low, however, because of low demand, which meant that the auctions cleared in the low-priced portion of the supply curves.

In some cases, substantially more DR was offered into the IAs than what went uncleared in the BRA, particularly during the third IA for the 2011/12 delivery year. However, prior to the 2012/13 delivery year, these additional DR supplies had little effect on IA clearing prices as nearly all of these suppliers offered at prices just above the BRA clearing price. The higher-priced DR offers were consistent with incentives under the prior IA design, because suppliers could be certified as ILR immediately prior to the delivery year and receive a capacity payment based on BRA price for that year. Under that structure, DR suppliers had an incentive to bid into the IAs only to possibly capture a price above the BRA price. With the revision of the IA design and the elimination of ILR (and incorporation of these DR supplies into the RPM auctions) for the 2012/13 delivery year, DR suppliers in the both the IAs and BRAs have begun offering significant amounts of supply over a large range of prices.

Market participants' demand bids in the IAs have been for small amounts of capacity at high prices and very high quantities at low prices. In fact, most demand bids submitted at a zero price. The qualitative shape of the demand curve in the first IA is different from the shape in the third IA, with the third IA having higher quantities of demand at higher prices. A relatively higher willingness to pay for replacement capacity in the third IA may be caused by a lack of time to find bilateral replacement transactions between the third IA and the delivery year.

Table 6
Summary of Major Incremental Auction Price Shifts and Causes

Year	Auction	Location	Causes of Major Price Changes Relative to BRA or Previous IA
2008/09	*3rd IA*	*RTO and EMAAC* -	Price decrease of $102/MW-day and $139/MW-day in RTO and EMAAC, respectively, caused by a small increase in supply from existing generation combined with a large reduction in offer prices from existing generation.
		SWMAAC -	SWMAAC IA price clears at the LDA price cap or just $14/MW-day higher than the BRA price, with relatively high prices in both cases caused by tight supply conditions. Only 5 MW of capacity went uncleared in the BRA and 21 MW was offered into the IA.
2009/10	*3rd IA*	*RTO and LDAs* -	Large price reductions of $62-$151/MW-day, depending on the location, are caused by reductions in offer prices from existing generation and generation uprates offered at low or zero prices. Increases in offered DR did not contribute to price reductions because these resources offered at prices above the BRA clearing price.
2010/11	*3rd IA*	*RTO and LDAs* -	Similar to 2009/10 third IA, large price reductions of $124 to $136/MW-day are caused by low offer prices from existing generation and uprates.
2011/12	*1st IA*	*RTO* -	Prices decrease $55/MW-day despite substantially reduced supply relative to uncleared BRA quantities. Demand bids have a large quantity but nearly all demand bids are at or very near zero, causing only a small quantity of low-priced supply offers to clear.
	3rd IA	*RTO* -	Price reduction of $105/MW-day relative to the BRA and $50/MW-day relative to the first IA caused by low generation offer prices relative to the BRA and IA, along with additional low-price DR offers. Despite a substantial increase in DR quantities, the great majority of DR offers were rationally submitted above the BRA clearing price.
			2.5% Holdback Introduced and New Incremental Auction Design is Implemented
2012/13	*1st IA*	*RTO* -	Uncleared portion of the BRA supply curve is very similar to the IA supply curve, with a substantial quantity of offers near the BRA clearing price, resulting in an RTO clearing price identical to the BRA price.
		MAAC and SWMAAC -	Capacity prices decrease by $117/MW-day despite reduced supply relative to BRA uncleared quantity. These reductions were caused primarily by a reduction in peak load forecast in MAAC.
		EMAAC -	Capacity price rises by a modest $14/MW-day in response to a nearly 2,000 MW reduction in CETL caused by a delay in the Susquehanna-Roseland transmission line. This large increase in the required quantity of internal capacity did not result in a large price increase because, similar to the rest of MAAC, existing generators substantially reduced their offer prices relative to the BRA.
	2nd IA	*RTO* -	Capacity prices decreased by $105/MW-day in EMAAC and subzones and by $3/MW-day below the already low first IA prices in all other LDAs. These price reductions were driven by a large reduction in the load forecast.

Sources and Notes:
Causes of price changes determined from analysis of auction bid data, supply curves, demand curves, and parameters.
From BRA parameters, results, and bid data, PJM (2007a-b, 2008a-c,e, 2009a-e,h-i, 2010a-b,f-h, 2011a-c,g).

3. Quantities Offered and Cleared

Table 7 shows the quantities of cleared and uncleared supply offers and demand bids in all incremental auctions conducted to date. BRA uncleared resources are also shown for reference, as a reasonable first assumption would be that many resources failing to clear the BRA might later offer into an IA. Supplier offers are shown separately for new generation, existing generation, and DR and EE. Buyer bids from generation owners are shown separately from bids from DR and EE owners.[37]

Table 7 shows that offered supplies in the third IA exceeded the uncleared BRA capacity by up to 3.7 GW, mostly related to DR that offered only into the third IA (but no earlier auctions) for that delivery year. We do not expect this same result to continue after the 2012/13 incorporation of DR into the auctions, since these resources are now offering significant amounts of capacity into the BRA. For the first and second IAs, offer quantities were less than the BRA uncleared supply by approximately 2 GW and 1 GW, respectively. These reductions in supply for the first and second IAs are mostly related to higher-priced generation that offered into the BRA but did not offer in the IAs. Among new generation resources that failed to clear the BRA, only 30% to 50% have subsequently offered into the IAs. This suggests that some suppliers of new generation or existing generation requiring substantial reinvestment have made their investment decisions contingent on whether they clear in the BRA. If they do not clear in the three-year forward BRA, they likely will not be available for that delivery year.

For existing generation resources, the quantities offered in the IAs for the 2009/10 and 2010/11 delivery years were 1.5 GW and 2.3 GW higher than the quantities uncleared in the BRA. Most of these increases were associated with capacity uprates.[38] For the 2011/12 and 2012/13 delivery years, 2.0 GW and 1.2 GW less existing generation was offered into the first IAs than in the BRA. Most of these reductions are associated with existing resources that have subsequently submitted retirement requests, although some are associated with reduced imports, equivalent demand forced outage rate ("EFORd") changes, derates, or ATSI units that were obligated to offer capacity into the IAs.

For DR and EE resources, the offer levels in the first IAs were 290 MW and 470 MW below the BRA uncleared quantities, while the offer levels in the third IAs were up to 3,980 MW above the BRA uncleared quantities. At first glance, these observations may seem to support the theory that DR and EE have a much greater ability to participate in non-forward auctions, but the data must be interpreted carefully given DR rule changes for the 2012/13 delivery year. Starting with the 2012/13 delivery year, the ILR option was eliminated, so these resources had to clear through auctions.

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37 Buy bids are submitted by market participants but are not associated with specific resources. For this reason, we have classified buy bids as DR and EE or generation based on the predominant resource holdings of the market participant. The vast majority of market participants offer only generation or only DR and EE.

38 Specifically, of the increase in supply from existing resources for those two years, approximately 63% was from generation uprates, 18% was from increased imports, 11% was from small generators that did not offer into the BRA, 5% was from EFORd decreases, and 3% was from FRR resources. From PJM (2011a).

Table 7
Summary of Incremental Auction Cleared and Uncleared Offers and Bids
(UCAP MW)

	2007/08	2008/09	2009/10	2010/11	2011/12		2012/13		2013/14	2014/15
SELL OFFERS										
Base Residual Auction										
Uncleared	**1,435**	**2,283**	**1,319**	**902**	**5,499**		**9,230**		**8,155**	**10,512**
New Generation	-	-	139	119	497		598		14	621
Existing Generation	1,435	2,103	1,136	755	4,714		5,748		4,393	8,454
DR and EE	-	180	44	29	288		2,884		3,748	1,437
Incremental Auctions		*3rd IA*	*3rd IA*	*3rd IA*	*1st IA*	*3rd IA*	*1st IA*	*2nd IA*		
Offered	n/a	**2,339**	**3,256**	**4,554**	**2,843**	**6,538**	**7,086**	**6,448**	n/a	n/a
New Generation	n/a	6	69	30	163	212	179	164	n/a	n/a
Existing Generation	n/a	2,310	2,656	3,073	2,680	2,056	4,492	3,802	n/a	n/a
DR and EE	n/a	23	531	1,452	-	4,270	2,415	2,483	n/a	n/a
Cleared	n/a	**1,032**	**1,798**	**1,846**	**361**	**1,557**	**1,689**	**838**	n/a	n/a
New Generation	n/a	6	19	30	-	175	95	76	n/a	n/a
Existing Generation	n/a	1,003	1,780	1,792	361	844	1,116	525	n/a	n/a
DR and EE	n/a	23	-	24	-	538	478	237	n/a	n/a
Uncleared	n/a	**1,307**	**1,457**	**2,708**	**2,481**	**4,981**	**5,397**	**5,610**	n/a	n/a
New Generation	n/a	-	50	-	163	37	84	87	n/a	n/a
Existing Generation	n/a	1,307	876	1,280	2,319	1,212	3,376	3,277	n/a	n/a
DR and EE	n/a	-	531	1,428	-	3,732	1,937	2,246	n/a	n/a
MARKET PARTICIPANT BUY BIDS										
Incremental Auctions		*3rd IA*	*3rd IA*	*3rd IA*	*1st IA*	*3rd IA*	*1st IA*	*2nd IA*		
Offered	n/a	**2,252**	**2,698**	**5,221**	**11,969**	**8,865**	**9,339**	**11,560**	n/a	n/a
Generation Suppliers	n/a	2,182	2,308	4,789	11,419	8,473	8,581	10,741	n/a	n/a
DR and EE Suppliers	n/a	70	390	432	550	393	758	819	n/a	n/a
Cleared	n/a	**1,032**	**1,798**	**1,846**	**361**	**1,557**	**1,749**	**3,215**	n/a	n/a
Generation Suppliers	n/a	992	1,409	1,414	141	1,164	1,403	2,754	n/a	n/a
DR and EE Suppliers	n/a	40	390	432	220	393	346	460	n/a	n/a
Uncleared	n/a	**1,220**	**899**	**3,375**	**11,607**	**7,308**	**7,590**	**8,345**	n/a	n/a
Generation Suppliers	n/a	1,190	899	3,375	11,278	7,308	7,178	7,987	n/a	n/a
DR and EE Suppliers	n/a	30	-	-	330	-	412	359	n/a	n/a

Sources and Notes:
From PJM supplier bidding data, PJM (2011a).
Buyers are classified as generation or demand suppliers based on the predominant resource type held.

In some cases, after a resource has made a capacity commitment through the BRA, it will have an unforeseen difficulty in meeting this obligation. Reasons might be a construction delay or a major equipment failure or derate. These suppliers can decommit their capacity without penalty as long as they can substitute replacement capacity through self-supply or bilateral transactions or by procuring replacement capacity in the incremental auctions. Market participants may also submit buy bids in the incremental auctions as a hedging measure, even if the procured capacity is not ultimately used to decommit another resource. In the incremental auctions held to date, generation owners have submitted 93% of total buy bids submitted and 80% of bids cleared. DR and EE suppliers have submitted the remaining 7% of buy bids and 20% of bids cleared. Demand in the incremental auctions prior to 2012/13 consisted only of market participants' buy bids, while demand in subsequent IAs also includes a portion related to changes in CETL, reliability requirements (the STRPT), and the incremental portion of the VRR curve.

Among generation owners, it appears that market participants have been using the IAs as a supplement to bilateral and self-supply options for managing their capacity obligations after the

BRA.[39] For generation owners, 79% of their full-year resource replacements have been through self-supply or bilateral transactions; only 66% of the capacity that generators have procured from the IAs has later been used to reduce capacity commitments. Generators have also been very active in substituting capacity for partial years, presumably to avoid penalties.[40] These generators appear to use the IAs as a hedging opportunity by procuring substantial quantities of replacement capacity (as indicated by their high bid quantities), but only if that capacity is available at very low prices (as indicated by their low clearing quantities).

Among DR suppliers, it appears that incremental auctions have represented their primary means of managing capacity obligations after the BRA. For DR suppliers, all capacity procured from the IAs has been used to replace full-year capacity decommitments. This IA capacity has replaced 86% of all decommitments from DR, with the remainder being replaced through self-supply or bilateral transactions.[41] Relative to generation owners, DR suppliers have been much less active in managing partial-year resource replacements.[42]

4. Incremental Auction Supply Curves

We have compared supply curves for each of the IAs to the uncleared portions of the corresponding BRA supply curves. We used this comparison to examine how offer quantities and prices change for supplies that fail to clear the BRA. Figure 8 and Figure 9 below show the (smoothed) mitigated supply curves for the 2011/12 delivery year (prior to the IA redesign and 2.5% holdback) and for 2012/13 delivery year (after the IA redesign and 2.5% holdback).

Prior to the redesign, there were four third IAs and one first IA. One of the most prominent features of the third IA supply curves was the large "shelf" of DR bids submitted at prices just above the BRA price as highlighted in Figure 8. This shelf was caused by inefficient incentives created by the previous ILR mechanism. These resources were allowed to receive a payment based on BRA clearing prices as long as their capacity was certified immediately prior to the delivery.[43] Under that system, demand resources had almost no incentive to offer into the BRA or first and second IAs. Their only incentive to offer in any auction was to capture potentially higher IA prices, which would happen only if the incremental auction cleared at a capacity price

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39 References in this paragraph to bilateral and self-supply replacement transactions refer only to delivery years 2008/09 through 2010/11. The reason for this is that many replacement transactions do not occur until immediately prior to, or even during, the delivery period, even if the replacement capacity was procured earlier. Partial year transactions especially are more common during the delivery year.

40 For example, for 2010/11, generation owners procured 1,414 MW in the third IA, which were used in 1,014 MW of full-year resource decommitments and another 1,507 MW of partial-year decommitments. Note that the same IA procured MW can be used multiple times for partial-year decommitments as these decommitments may be for only days or weeks. For the same delivery year, self-supply or bilateral capacity transactions were used in order to decommit another 4,373 MW of full-year obligations and another 18,954 MW of partial-year obligations.

41 Again, these reported numbers represent only delivery years 2008/09 through 2010/11.

42 For example for 2010/11, DR suppliers procured 432 MW in the third IA, all of which was used to replace committed capacity for a full year. An additional 54 MW of full-year replacements were made through self-supply or bilateral transactions, and no DR suppliers submitted any partial-year capacity replacements.

43 See PJM (2011d), p. 29.

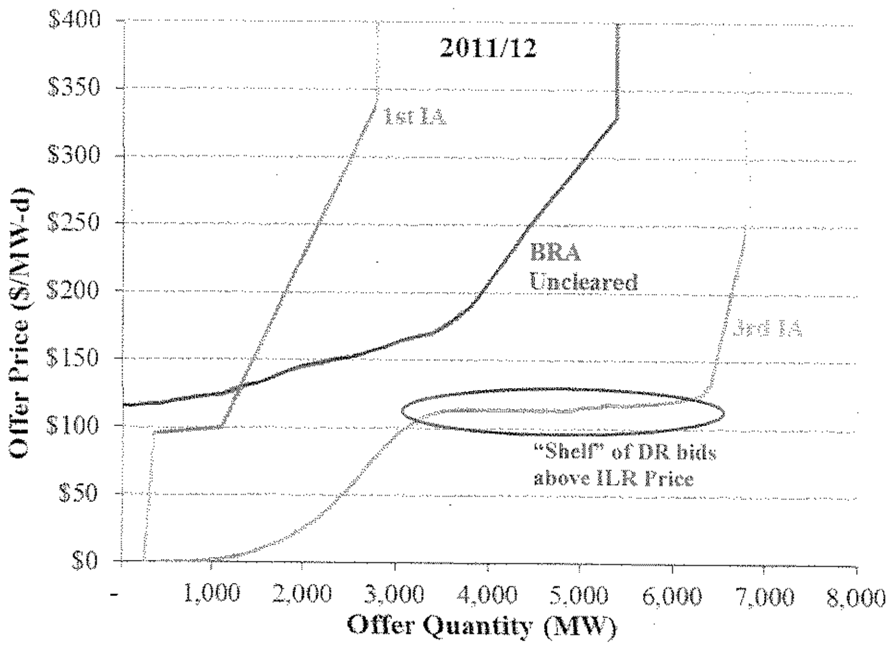
above the BRA prices otherwise awarded to ILR. As a result, prior to the 2012/13 delivery year, a rational DR supplier would either opt out of participating in any of the auctions or participate in the IAs by offering at a price above the BRA clearing price. After the elimination of ILR (and full incorporation of DR into auctions starting with the 2012/13 delivery year), this incentive was eliminated.

After the 2012/13 redesign, there have only been two incremental auctions conducted, providing limited evidence for our evaluation. However, it is noteworthy to observe from Figure 9 that the IA supply curves for the 2012/13 delivery year are very similar in shape to the uncleared portion of the BRA supply curve for prices below approximately \$150/MW-day. Much of this supply is from DR offers that had similar offer levels in the BRA and IAs. It is not yet clear how the offer prices for DR supplies may differ in the third IA immediately prior to the delivery year or how substantially these offers are influenced by changing expectations about curtailment levels.

For generation supplies (both before and after the redesign), IA offer curves have been much steeper than the BRA supply curves, with most high-cost supplies dropping out prior to the IAs and many other generation suppliers offering at zero. The withdrawal of high-cost generation supplies above \$150/MW-day is visible in the 2012/13 supply curves shown in Figure 8, indicating that some generators have made decisions about whether to invest in a new resource or reinvest in an existing resource contingent on the outcome of the BRA. However, we have also observed occasions when additional generation supplies that were not offered in the BRA were offered into the IAs at a zero price. For example, in the third IAs for the 2009/10 and 2010/11 delivery years, a large number of uprates were offered that were previously not offered in the BRA. Given their zero offer prices in the IAs, we believe it is likely that most of these uprate investment decisions were made based on the suppliers' longer-term outlook for capacity and energy prices and not specifically based on prices available in the IAs.

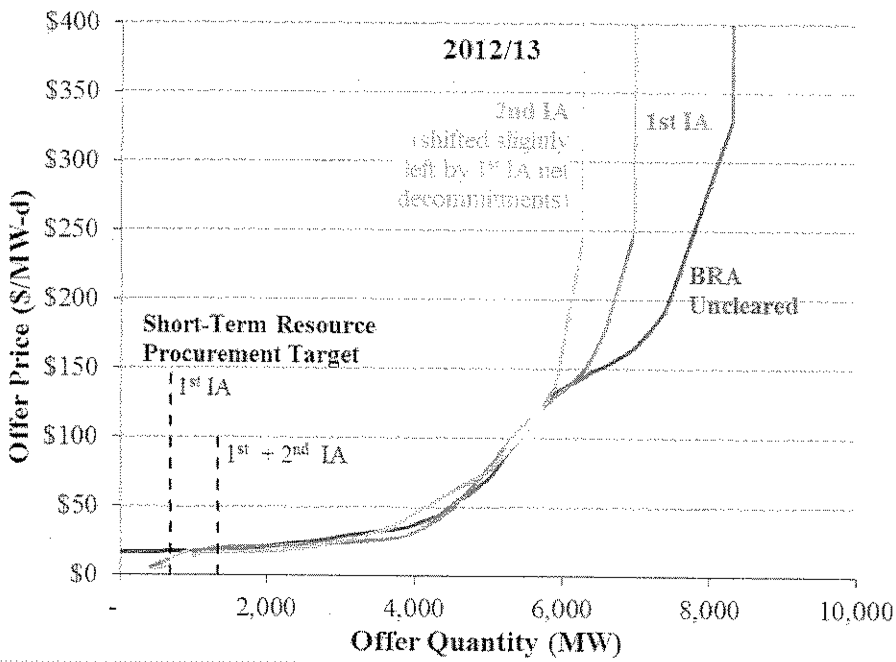
Overall, incremental auction results from the first two auctions after the redesign are promising, but more experience needs to be gained to fully assess IA performance. Prices in the IAs for the 2012/13 delivery year have been consistent with changes in market conditions between the BRA and the IAs, including load forecast reductions and the delay of the Susquehanna-Roseland transmission line. In addition to this preliminary empirical evidence, there are several other reasons to expect that IA prices under the new design will be more consistent with BRA prices and market fundamentals, including: (1) the incorporation of the incremental portion of the VRR curve in the IAs, (2) the reliability requirement adjustments that may be made prior to IAs in the future, and (3) DR and EE resources will have the option to offer into either the BRA or the IAs, which may allow some price convergence.

Figure 8
2011/12 Incremental Auction Supply Curves
(Before 2012/13 Redesign and without 2.5% Holdback)



Sources and Notes:
From PJM supplier bidding data, PJM (2011a). Smoothed to mask confidential market data.

Figure 9
2012/13 Incremental Auction Supply Curves
(After 2012/13 Redesign and with 2.5% Holdback)



Sources and Notes:
From PJM supplier bidding data, PJM (2011a). Smoothed to mask confidential market data.

C. Cumulative Additions, Retirements, and Retentions

The following discussion summarizes the cumulative changes in capacity commitments from all base and incremental auctions to date—since just before the introduction of RPM through the commitments made in the most recent BRA for the 2014/15 delivery year. Unlike the previous sections covering individual auction results on a UCAP basis, the discussion *in this section refers all results on an installed capacity (ICAP) basis.*

We first summarize all gross and net additions to capacity in PJM, including resources contributing to Fixed Resource Requirement (FRR) plans and resources added through new RTO members. We report all current or planned internal generation capacity, total imports and exports, and current or planned demand-side resources. Among these total system resources, we include a breakdown of the capacity that is committed to providing resource adequacy either through FRR commitments or by clearing through auctions, as well as summarizing total resources that are RPM-qualified but that are not committed for capacity purposes either because they have gone uncleared in the auctions or because they have been excused from auctions.

We then examine in greater detail the gross and net capacity additions committed through base and incremental auctions, excluding FRR capacity and new RTO members. We explicitly report the quantities of planned capacity increases that were offered into auctions but failed to clear (indicating that they may not materialize), as well as the quantities of existing capacity that have failed to clear (indicating that they may retire). We also report the net capacity exchange between RPM auctions and FRR entities. We examine these gross and net commitments at the RTO and LDA levels, and compare committed totals to the target commitment levels required for resource adequacy. These committed net resource additions are the most relevant evidence for evaluating RPM's track record for attracting and retaining sufficient capacity for resource adequacy.

1. Net Capacity Additions (Including FRR and RTO Expansion)

Table 8 summarizes installed capacity reductions and additions in PJM relative to the pre-RPM levels in 2006/07 through results for the most recent auction for 2014/15. The table separates auction-committed capacity from FRR-committed capacity and from capacity gained through territory expansions. The top portion of the table reports total historical and planned capacity reductions and additions, while the bottom reports the total capacity commitments for resource adequacy through FRR or auctions (as well as uncommitted capacity that may retire or fail to come online).

Since RPM began with delivery year 2007/08, PJM has added 36.3 GW of ICAP through completed or planned additions, uprates to internal generation, increased imports, decreased exports, and increased demand-side resources. Of these gross additions, 4.9 GW are FRR capacity and 31.4 GW are RPM auction capacity. Derates and retirements over the same time period have totaled 8.4 GW. Of these gross reductions, 0.4 GW are FRR capacity and 8.1 GW are auction capacity. An additional 13.9 GW of pre-existing generation capacity was acquired through RTO expansions to integrate ATSI and DEOK into PJM.

Overall, these additions, reductions, and expansions have resulted in a net increase of 41.7 GW in installed capacity available to meet the required reserve margin. For the 2014/15 delivery year, of the total 205.8 GW of installed or planned capacity in PJM, 33.6 GW is committed to

provide reliability through FRR commitments and another 157.3 GW is committed through RPM auctions, sufficient to exceed respective resource adequacy targets. The remaining 14.9 GW of capacity is not committed to provide resource adequacy because it was either excused from offering in auctions or failed to clear in the 2014/15 BRA.

Focusing on generation, PJM had 164.9 GW of internal generating capacity in 2006/07, immediately prior to RPM's implementation. At the outset of RPM, 23.1 GW of this existing capacity was incorporated through the FRR option. Since then, there have been gross additions of 12.7 GW of internal generation capacity in the RTO. This includes 7.6 GW of newly built or reactivated generation,(650 MW from FRR resources) and 5.1 GW of uprates to existing generation (420 MW to FRR resources).[44] These additions have been offset by 8.4 GW of reductions to internal generation through plant derates and retirements. Through the current delivery year of 2011/12, only 710 MW of generation has retired; however, based on pending deactivation requests, the rate of retirement will increase over the next three delivery years to reach a cumulative total of 5.3 GW by 2014/15. Of these retirements, 2.3 GW are coal plants, 1.7 GW are gas (primarily aging gas steam plants), 1.1 GW are oil plants, and the remainder are small units of other fuel types. Including completed and planned new units, reactivation, uprates, retirements, and derates, there has been a cumulative net addition of 4.2 GW to existing internal generating capacity in PJM through delivery year 2014/15.

PJM was a net *exporter* of 2.6 GW in 2006/07. By 2014/15, it will be a net *importer* of 6.4 GW for a total change of 9.0 GW. Gross exports declined after RPM was implemented, decreasing from 5.3 GW in 2006/07 to 1.2 GW in 2014/15. Commitments for imports increased from 2.7 GW in 2006/07 to 7.6 GW in 2014/15. Of the 9.0 GW increase in net imports, 4.2 GW occurred in 2014/15 coincident with the incorporation of DEOK into RPM, primarily from resources owned by Duke but not within the portion of Duke that was incorporated into PJM.

Demand resources have grown substantially since RPM was implemented. During the 2006/07 delivery year, 1.7 GW of demand-side resources contributed to resource adequacy as Active Load Management ("ALM"). For 2014/15, 16.4 GW of DR and EE capacity has been committed through FRR or offered into RPM auctions (in ICAP terms).[45]

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[44] 650 MW of new generation that offered into the 2014/15 auction did not clear and may not come online.

[45] Note that the apparent decrease in demand resources for 2013/14 relative to the prior and subsequent years is somewhat misleading. The reason for this apparent drop is that no incremental auctions have yet been conducted for 2013/14. We expect that subsequently planned resources that have offered into the 2012/13 IAs and 2014/15 BRA will also offer into the 2013/14 IAs when they are conducted.

Table 8
Cumulative Changes in Capacity under RPM
(ICAP MW)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
INTERNAL GENERATION	**164,914**	**164,556**	**165,327**	**165,966**	**167,553**	**171,655**	**171,559**	**181,243**	**183,009**
Existing Generation Prior to RPM	**164,914**	**164,914**	**164,914**	**164,914**	**164,914**	**165,663**	**166,460**	**177,035**	**178,769**
Non-FRR Capacity as of 2006/07	141,831	141,831	141,831	141,831	141,831	141,831	141,831	141,831	141,831
FRR Capacity as of 2006/07	23,083	23,083	23,083	23,083	23,083	23,083	23,083	23,083	23,083
ATSI/DEOK Prior to Joining PJM	n/a	n/a	n/a	n/a	n/a	749	1,546	12,121	13,855
Generation Reductions	n/a	**(904)**	**(1,269)**	**(2,110)**	**(2,412)**	**(2,675)**	**(5,713)**	**(7,136)**	**(8,446)**
Retirements	n/a	*(340)*	*(440)*	*(440)*	*(617)*	*(710)*	*(3,035)*	*(4,331)*	*(5,341)*
FRR Capacity	n/a	-	-	-	-	-	-	-	-
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	-	(322)
Auction Capacity (w/o ATSI/DEOK)	n/a	(340)	(440)	(440)	(617)	(710)	(3,035)	(4,331)	(5,019)
Derates	n/a	*(564)*	*(829)*	*(1,670)*	*(1,795)*	*(1,965)*	*(2,678)*	*(2,805)*	*(3,105)*
FRR Capacity	n/a	(94)	(138)	(357)	(357)	(357)	(361)	(361)	(364)
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	-	-
Auction Capacity (w/o ATSI/DEOK)	n/a	(470)	(691)	(1,313)	(1,439)	(1,608)	(2,318)	(2,445)	(2,742)
Generation Additions	n/a	**546**	**1,681**	**3,155**	**5,043**	**8,243**	**10,387**	**11,104**	**12,686**
New Generation	n/a	*129*	*340*	*882*	*1,845*	*3,838*	*4,924*	*5,662*	*6,763*
FRR Capacity	n/a	-	-	-	595	595	595	655	655
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	685	708
Auction Capacity (w/o ATSI/DEOK)	n/a	129	340	882	1,250	3,243	4,329	4,322	5,400
Uprates	n/a	*417*	*1,040*	*1,947*	*2,896*	*3,573*	*4,622*	*4,610*	*5,083*
FRR Capacity	n/a	64	84	254	254	295	354	380	416
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	-	-
Auction Capacity (w/o ATSI/DEOK)	n/a	352	956	1,693	2,641	3,279	4,268	4,230	4,667
Reactivations	n/a	-	*302*	*326*	*303*	*832*	*841*	*832*	*841*
FRR Capacity	n/a	-	-	-	-	-	-	-	-
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	-	-
Auction Capacity (w/o ATSI/DEOK)	n/a	-	302	326	303	832	841	832	841
New Generation Later Cancelled	n/a	-	-	**8**	**8**	**424**	**426**	**240**	-
NET IMPORTS	**(2,563)**	**(1,390)**	**(1,590)**	**474**	**35**	**(305)**	**1,375**	**2,173**	**6,390**
Gross Imports	*2,711*	*2,984*	*2,616*	*2,715*	*3,413*	*3,084*	*4,159*	*4,797*	*7,620*
Imports to FRR	n/a	1,275	858	850	1,131	1,095	1,506	1,265	3,328
Imports to Auctions	n/a	1,709	1,758	1,865	2,282	1,989	2,653	3,532	4,292
Gross Exports	*(5,274)*	*(4,374)*	*(4,206)*	*(2,241)*	*(3,378)*	*(3,389)*	*(2,784)*	*(2,625)*	*(1,230)*
DEMAND RESOURCES	**1,679**	**2,135**	**4,467**	**7,576**	**9,344**	**11,026**	**14,621**	**13,732**	**16,350**
FRR DR/EE	n/a	432	438	438	452	450	473	473	501
Auction DR/EE (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	30	124	1,342	1,082
ILR and Auctions (w/o ATSI/DEOK)	1,679	1,703	4,029	7,138	8,892	10,546	14,024	11,917	14,767
TOTAL INSTALLED CAPACITY	**164,030**	**165,300**	**168,203**	**174,015**	**176,930**	**182,378**	**187,556**	**197,150**	**205,762**
Committed Capacity	n/a	**163,279**	**165,392**	**172,135**	**174,487**	**174,987**	**171,643**	**187,280**	**190,894**
FRR Commitments	n/a	24,717	24,954	25,316	26,306	25,921	26,302	25,793	33,613
ILR and Cleared DR/EE	n/a	1,703	4,029	7,138	8,892	10,576	8,065	9,634	14,458
Cleared Gen (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	3	-	10,908	8,501
Cleared PJM Gen (w/o ATSI/DEOK)	n/a	135,150	134,693	137,858	137,015	136,548	134,686	137,413	130,030
Cleared Imports	n/a	1,709	1,716	1,823	2,274	1,939	2,590	3,532	4,292
Uncommitted Capacity	n/a	**2,020**	**2,812**	**1,880**	**2,444**	**7,391**	**15,913**	**9,870**	**14,868**
FRR Excused	n/a	43	357	553	759	1,178	1,692	1,194	2,546
Uncleared DR/EE	n/a	n/a	n/a	n/a	n/a	n/a	6,083	3,625	1,391
Uncleared Gen (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	746	1,546	1,898	4,031
Uncleared PJM Gen (w/o ATSI/DEOK	n/a	1,510	2,047	1,013	1,145	5,015	6,489	3,143	6,191
Uncleared Imports	n/a	0	43	42	8	50	64	-	-
Other Excused	n/a	467	365	272	531	402	40	10	710

Sources and Notes: Generation, DR, and EE are cumulative for all BRAs and IAs, reported in ICAP terms, PJM (2011a).

Among all of these existing and planned resources, 191.1 GW of installed capacity is committed for 2014/15, including 33.6 GW of FRR resources, 33.6 GW of cleared demand resources, 138.5 GW of cleared internal generation, and 4.3 GW of cleared imports. Another 4.0 GW of incremental commitments are expected to be procured, associated with the short-term resource procurement target.[46] Uncommitted existing or planned capacity resources total 14.8 GW. These uncommitted resources include 2.5 GW of excused FRR capacity, 0.7 GW of other excused generation, 1.4 GW of uncleared demand resources, and 10.2 GW of uncleared internal generation. Some of these uncleared resources represent planned resources that may not come online because they have failed to clear the BRA, while others represent existing resources that may retire before the 2014/15 delivery year.

It is particularly instructive to examine the changes in resource commitments between the 2013/14 and 2014/15 years, when the proposed EPA HAP regulations are expected to come into force. Auction-based internal generation commitments decreased by 9.8 GW between the two base auctions, caused primarily by a response to the environmental regulations as well as a reduction in load forecasts. Uncleared internal generation resources totaled 10.2 GW (up from 5.0 GW in 2013/14), mostly consisting of coal units in the unconstrained RTO. There were also 2.5 GW of FRR-excused resources (up from 1.2 GW) and 0.7 GW of other excused resources (increased from near zero). These withdrawals may also be related to a response to the HAP regulation. Despite these reductions in internal generation commitments, the RTO has sufficient existing and planned resources procured to meet resource adequacy requirements in 2014/15 (assuming the 2.5% STRPR will be successfully procured in the IAs). The internal reductions in generation commitment were compensated for by a large 4.8 GW increase in demand resource commitments, a 1.4 GW reduction in exports, and other resource adjustments (all in ICAP).[47]

2. Net Capacity Additions (Excluding FRR and RTO Expansion)

Excluding FRR and new RTO members, PJM has added 28.4 GW (ICAP) of gross committed and 13.1 GW of net committed capacity supply under RPM auctions, as shown in Figure 10 and Table 9. The gross committed additions are from 11.8 GW of new demand resources, 6.9 GW of increases in net imports, 4.8 GW of new generation, 4.1 GW of uprates, and 0.8 GW of reactivations. These additions were offset by 15.3 GW of gross capacity reductions, including 5.0 GW of retirements, 2.7 GW of derates, 6.8 GW of capacity removed from auctions for FRR, and 0.7 GW of generation excused from auctions. As discussed in Section II.A, these net increases have been sufficient to sustain capacity surpluses in the RTO at prices below Net CONE despite some load growth over the period and environmental challenges to supply.

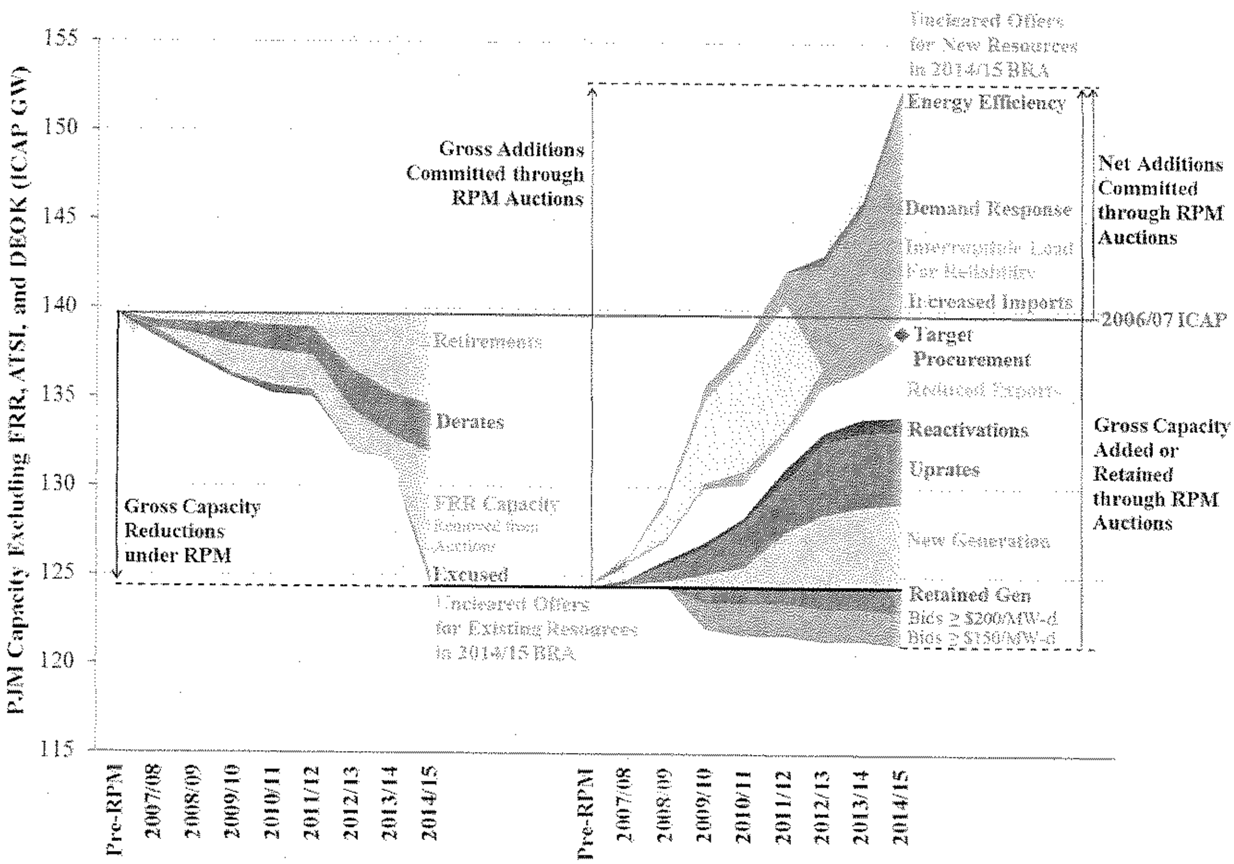
Figure 10 shows these gross and net capacity additions relative to the pre-RPM installed capacity. The red horizontal line at 140 GW shows the 2006/07 installed capacity, including all internal generation, net imports, and Active Load Management resources. The left panel of the chart shows gross capacity reductions of 15.3 GW and the composition of these decommitments. The right panel shows the composition of 28.4 GW in increased resource commitments. A total capacity of 153 GW for the 2014/15 delivery year, after reductions to existing capacity and

46 The STRPT is reported here on an ICAP basis for the entire RTO including territory expansions, see PJM (2011b).

47 Increases in imports and FRR commitments are not reported here as offsetting factors because these commitment increases were largely related to the DEOK territory expansion.

committed increases, is indicated by the dashed line at the top of the right side of the figure. This 2014/15 capacity is greater than the target procurement to meet resource adequacy requirements for the 2014/15 delivery year (shown as the red diamond), demonstrating a capacity surplus through 2014/15.

Figure 10
RTO Net Capacity Additions Committed in RPM Auctions
Excluding FRR Capacity and RTO Expansions



Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms.
Gross and net changes represent BRA and IA capacity commitments (offered but uncleared resources are in gray).
From PJM bid and resource data, PJM (2007a).

Reductions. The 15.3 GW (ICAP) of gross reductions include retirements, derates, reductions in imported capacity, withdrawal of FRR capacity that previously offered into auctions, and excused capacity that previously offered into auctions. Deducting these from the 2006/07 baseline creates the new baseline of remaining existing supply at 124 GW.

- The largest share of reductions has been from FRR resources that were offered into the first RPM auctions in 2007/08 but have since stopped offering into RPM auctions. Many of these of 6.8 GW of FRR withdrawals occurred between the 2013/14 and 2014/15 auctions and are likely related to the proposed EPA regulations.

- Retirements of 5.0 GW and derates of 2.7 GW comprise most of the remaining reductions, with a small contribution from other capacity excused from the RPM auctions.
- As shown, there are also 5.0 GW of uncleared existing generation resources that offered into the 2014/15 BRA and failed to clear, but have not yet retired. These resources are shown in light gray at the bottom of the right panel. We do not deduct these from the existing baseline because they have not yet retired and could yet commit through future incremental or base auctions. However, we note that these units would likely retire in the future if they also fail to clear in subsequent auctions. As explained in Section II.A, these potential retirements could reduce, but not eliminate, the overall capacity surplus in the RTO.

Additions: Gross additions under RPM include newly-built generation, uprates to existing generation, reactivations, reduced exports, increased imports, and increases to demand-side resources. Adding these to the 124 GW baseline of remaining existing resources yields a installed capacity of 153 GW for the 2014/15 delivery year. These increases consider only committed additions, while uncleared new resources are shown in light gray at the top of the right panel. The 28.4 GW (ICAP) of committed resource additions under RPM are composed of:

- 11.8 GW of increased demand response and energy efficiency (relative to the pre-RPM levels of ALM resources). Levels of DR under RPM have been steadily increasing, with the exception of 2012/13, when many suppliers stopped using the ILR mechanism and were incorporated into RPM auctions. However, additional demand resources may yet be procured in through the final incremental auction for the 2012/13 delivery year.
- 4.9 GW of new generation construction, 4.1 GW of capacity uprates, and 0.8 GW of reactivations.
- 6.9 GW of increased imports, resulting in PJM becoming a net importer of capacity.
- 2.5 GW of offers for new resources that failed to clear for the in 2014/15 delivery year due to offer prices in excess of auction clearing prices. Prior auctions showed similar or much larger amounts of uncleared new resources. We do not treat these uncleared new resources as additions, however, even though they could have been committed at higher market prices, if they had been needed.

Retentions: "Retained capacity" under RPM is a somewhat arbitrary determination, but for reference we show the quantity of capacity that has cleared in RPM auctions after offering their capacity at prices above \$150/MW-day and \$200/MW-day thresholds. These relatively high-priced offers from existing resources indicate that the resource required significant investments and would likely have retired had they failed to clear in the auctions.[48] Based on those indicators, 3.3 GW of generation capacity has been retained through RPM after having offered into the RPM auctions at prices of \$150/MW-day or more. All of these resources were in the

[48] We recognize that the identification of "retained" generation under RPM is somewhat arbitrary and dependents on what alternative resource adequacy construct would exist in place of RPM. We do not attempt any such theoretical comparison but instead simply report resources that may have been considering retirement (as indicated by their auction bid levels) but cleared in RPM auctions and thus remained committed.

MAAC LDA, where prices cleared above the $150/MW-day threshold. Clearing prices in the unconstrained RTO have been generally been lower than this threshold, but may also have retained generation that otherwise would have retired.[49]

Table 9
RTO Net Capacity Additions Committed in RPM Auctions
Excluding FRR Capacity and RTO Expansions

	Pre-RPM	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
EXISTING CAPACITY IN 2006/07									
Internal Generation	164,914	164,914	164,914	164,914	164,914	164,914	164,914	164,914	164,914
Active Load Management	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679
Imports	1,436	1,436	1,436	1,436	1,436	1,436	1,436	1,436	1,436
Exports	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)
2006/07 FRR Generation	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)
Total Capacity in 2006/07	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**
CAPACITY REDUCTIONS									
Retirements		(340)	(440)	(440)	(617)	(710)	(3,035)	(4,331)	(5,019)
Derates		(470)	(691)	(1,313)	(1,439)	(1,608)	(2,318)	(2,445)	(2,742)
Net FRR Capacity Removed from Auctions		(0)	(998)	(1,614)	(1,908)	(1,943)	(2,345)	(1,492)	(6,830)
Excused Capacity		(467)	(365)	(272)	(531)	(402)	(40)	(10)	(710)
Net Reductions in ILR		(99)	-	-	-	-	-	-	-
Total Reductions		**(1,376)**	**(2,495)**	**(3,639)**	**(4,494)**	**(4,663)**	**(7,737)**	**(8,277)**	**(15,300)**
Uncleared Offers for Existing Resources		*(1,291)*	*(1,866)*	*(595)*	*(796)*	*(3,820)*	*(5,360)*	*(2,976)*	*(4,958)*
RETAINED CAPACITY									
Bids Above $200/MW-d		0	0	870	871	871	1,156	1,169	1,417
Additional Bids Above $150/MW-d		-	-	1,478	1,874	1,874	1,874	1,845	1,845
Total Prevented Reductions		**0**	**0**	**2,348**	**2,745**	**2,746**	**3,031**	**3,015**	**3,262**
CAPACITY INCREASES									
New Generation		129	340	707	1,118	3,079	4,095	4,307	4,750
New Generation Later Cancelled		-	-	8	8	8	8	240	-
Uprates		279	902	1,513	2,522	2,885	4,044	4,182	4,088
Reactivations		-	302	326	303	752	606	832	841
Net Reductions in Exports		754	953	2,983	1,799	1,749	2,472	2,546	4,040
Net Increases in Imports		273	280	387	838	503	1,154	2,096	2,856
ILR & DR Additions (from ALM baseline)		124	2,351	5,458	7,214	8,793	5,787	6,917	11,006
Energy Efficiency		-	-	-	-	74	567	654	793
Total Cleared Increases		**1,559**	**5,128**	**11,381**	**13,801**	**17,842**	**18,732**	**21,773**	**28,375**
Uncleared Offers for New Resources		*219*	*224*	*460*	*357*	*1,245*	*7,183*	*2,834*	*2,521*
Net Committed Capacity Additions	**0**	**183**	**2,633**	**7,742**	**9,307**	**13,178**	**10,995**	**13,497**	**13,075**
Installed Capacity Plus Net Additions	**139,672**	**139,855**	**142,305**	**147,414**	**148,979**	**152,850**	**150,668**	**153,169**	**152,747**

Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms
Gross and net changes are BRA and IA capacity commitments (resources offered but uncleared are separately reported).
From PJM bid and resource data, PJM (2007a).

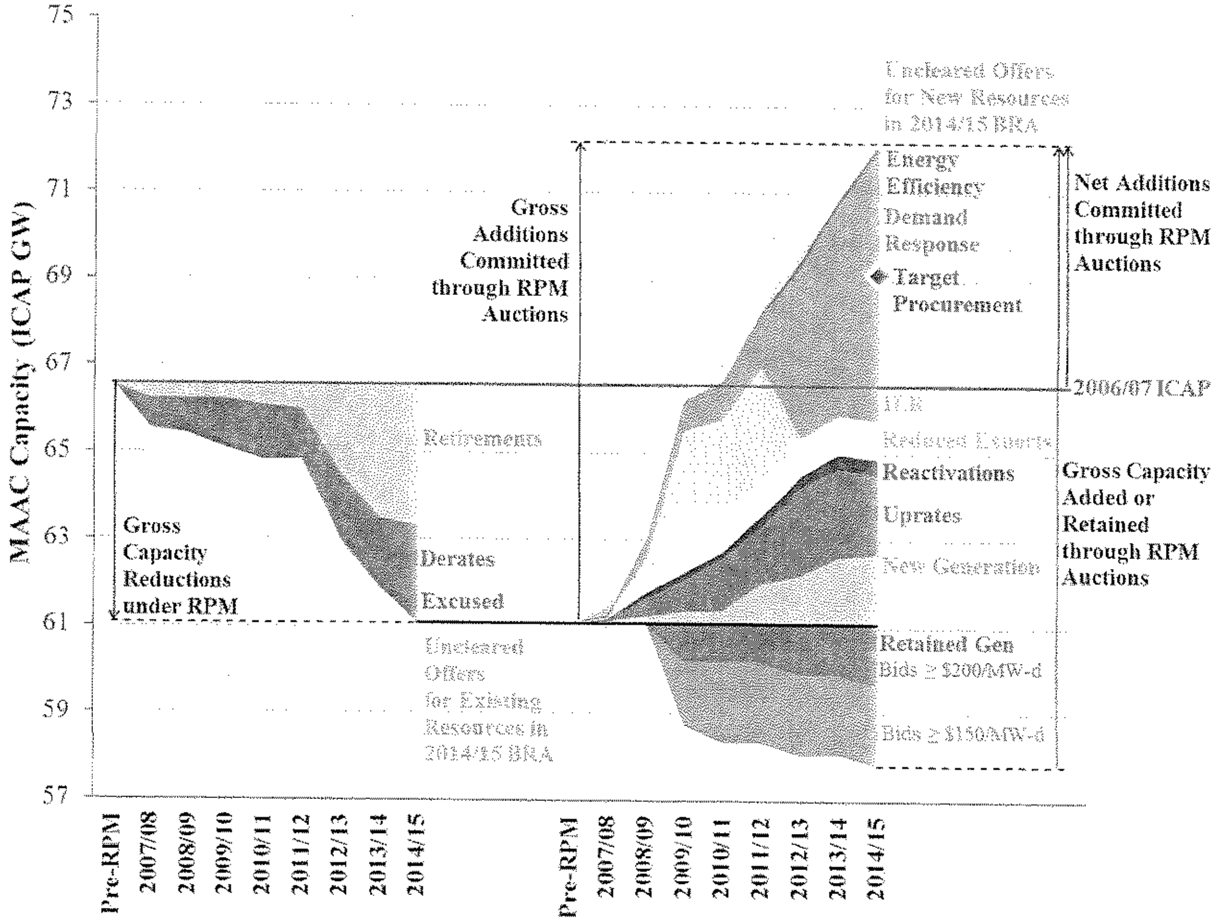
3. Net Additions Committed in the MAAC LDA

Figure 11 and Table 10 report the capacity reductions and committed additions through RPM auctions for the Mid-Atlantic Area Council (MAAC) LDA. In MAAC, a net 5.6 GW (ICAP) of capacity increases has been committed through 2014/15. Compared to the RTO, the LDA saw

49 Prices cleared above $150/MW-day only one time in the unconstrained RTO, clearing at $174/MW-day in 2010/11. See Table 1.

proportionately somewhat greater reductions in generating capacity, fewer generation additions, but greater increases in demand resources.[50] As of the recent BRA for the 2014/15 delivery year, MAAC has slightly lower uncleared offers for existing resources and slightly more uncleared offers for new resources, consistent with a smaller overall capacity surplus in the LDA.[51]

Figure 11
MAAC Net Capacity Additions Committed in RPM Auctions



Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms.
Gross and net changes represent BRA and IA capacity commitments (offered but uncleared resources are in gray).
From PJM bid and resource data, PJM (2007a).

Reductions. Among the 5.5 GW of capacity reductions, the largest share is accounted for in the 3.2 GW of pending retirements, scheduled to occur starting in 2012/13. Capacity derates of

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[50] As a fraction of 2014/15 installed capacity and committed increases, generation additions account for 6.3% of the RTO total and 5.3% of the MAAC total, while demand resource increases account for 7.8% in the RTO and 8.9% in MAAC; generation reductions represented 5.1% of the 2014/15 capacity in the RTO and 6.8% in MAAC.

[51] As a fraction of 2014/15 installed capacity and committed increases, uncleared existing resources were 3.2% in the RTO and 2.4% in MAAC while uncleared new resources were 1.7% in the RTO and 3.2% in MAAC.

1.6 GW comprise most of the remaining reductions, with the remaining 0.6 GW from an increase in excused capacity. An additional 1.7 GW of uncleared existing generation resources are units that may be at risk for retirement if they do not clear in upcoming incremental or base auctions.

Additions. The 11.1 GW of additional capacity commitments in MAAC are composed of 6.4 GW of increases in demand-side resources, 1.6 GW of new generation, 1.8 GW of uprates, and 0.9 GW of reductions in exports. In addition to the capacity additions that have been committed under RPM auctions, another 2.3 GW of uncleared new supply was available in the most recent auction.

Retentions. 3.3 GW of generation capacity has been retained through RPM after having offered into the RPM auctions at prices of $150/MW-day or more. The largest quantity of capacity retention occurred in the BRA for the 2009/10 delivery year, in which several generation resources, especially in SWMAAC, required environmental upgrades to continue operating, as discussed in our 2008 report.[52]

Table 10
MAAC Net Capacity Additions Committed in RPM Auctions
(ICAP MW)

	Pre-RPM	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
EXISTING CAPACITY IN 2006/07									
Internal Generation	67,336	67,336	67,336	67,336	67,336	67,336	67,336	67,336	67,336
Active Load Management	795	795	795	795	795	795	795	795	795
Exports	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)
2006/07 FRR Generation	-	-	-	-	-	-	-	-	-
Total Capacity in 2006/07	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**
CAPACITY REDUCTIONS									
Retirements		(340)	(340)	(340)	(482)	(575)	(2,036)	(3,070)	(3,243)
Derates		(307)	(454)	(997)	(1,044)	(1,059)	(1,504)	(1,595)	(1,634)
Excused Capacity		(357)	(365)	(137)	(232)	(102)	(40)	(10)	(630)
Net Reductions in ILR		(64)	-	-	-	-	-	-	-
Total Reductions		**(1,067)**	**(1,159)**	**(1,474)**	**(1,758)**	**(1,736)**	**(3,580)**	**(4,675)**	**(5,507)**
Uncleared Offers for Existing Resources		*(400)*	*(1,141)*	*(32)*	*(566)*	*(3,181)*	*(1,563)*	*(761)*	*(1,698)*
RETAINED CAPACITY									
Bids Above $200/MW-d		0	0	870	871	871	1,156	1,169	1,417
Additional Bids Above $150/MW-d		-	-	1,478	1,874	1,874	1,874	1,845	1,845
Total Prevented Reductions		**0**	**0**	**2,348**	**2,745**	**2,746**	**3,031**	**3,015**	**3,262**
CAPACITY INCREASES									
New Generation		66	164	281	303	929	1,134	1,314	1,614
New Generation Later Cancelled		-	-	8	8	8	8	240	-
Uprates		46	414	721	1,222	1,309	2,022	2,044	1,849
Reactivations		-	142	192	143	272	281	352	361
Net Reductions in Exports		37	149	1,548	825	760	847	875	875
ILR & DR Additions (from ALM baseline)		64	1,092	2,416	3,104	3,880	3,988	4,884	6,209
Energy Efficiency		-	-	-	-	74	182	147	193
Total Cleared Increases		**212**	**1,961**	**5,165**	**5,605**	**7,232**	**8,461**	**9,855**	**11,100**
Uncleared Offers for New Resources		*182*	*128*	*117*	*201*	*1,075*	*2,379*	*34*	*2,283*
Net Committed Capacity Additions	**0**	**(855)**	**801**	**3,692**	**3,848**	**5,496**	**4,881**	**5,181**	**5,593**
Installed Capacity Plus Net Additions	**66,581**	**65,727**	**67,383**	**70,273**	**70,429**	**72,077**	**71,463**	**71,762**	**72,175**

Sources and Notes:

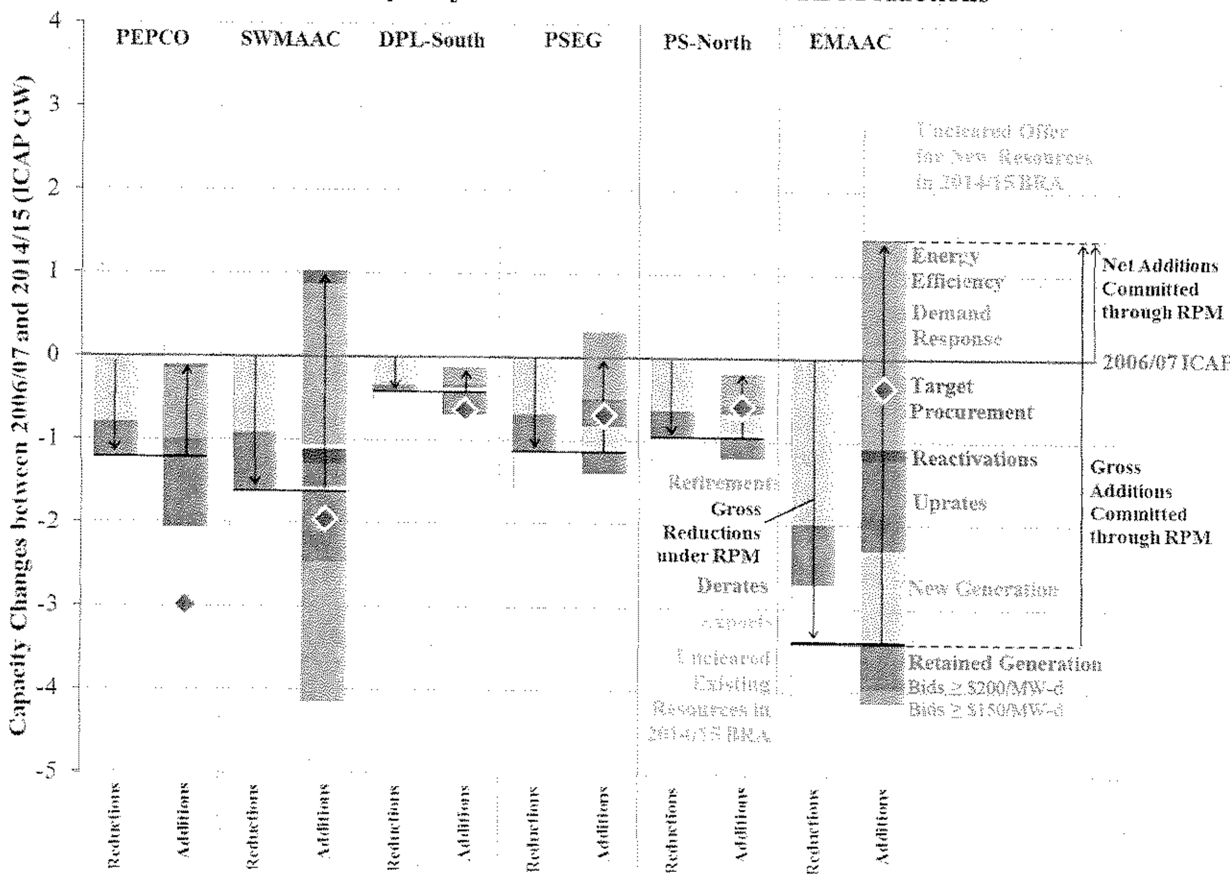
[52] See Pfeifenberger and Newell, *et al.* (2008), pp. 15, 22-24, 112-115.

All generation, DR, and EE values are cumulative totals in ICAP terms. Gross and net changes are BRA and IA capacity commitments (resources offered but uncleared are separately reported). From PJM bid and resource data, PJM (2007a).

4. Net Additions Committed in Smaller LDAs

Figure 12 and Table 11 summarize capacity reductions and additions similar to that presented in the above discussion for the RTO and MAAC. This information is presented for all of the other, smaller LDAs currently modeled in RPM. For these LDAs, these reductions and additions are not shown on an annual basis but, rather, as the total changes between pre-RPM levels and the results for the 2014/15 delivery year.

Figure 12
LDA Net Capacity Additions Committed in RPM Auctions



Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms
Gross and net changes represent BRA and IA capacity commitments (offered but uncleared resources are in gray).
Target procurement is reliability requirement less STRPT and CETL, converted to ICAP equivalent, from PJM (2011b).
From PJM bid and resource data, PJM (2007a).

Our primary observations are as follows:

- The largest of these LDAs—EMAAC, SWMAAC, and PSEG—had 1,440 MW, 1,030 MW, and 310 MW of *net capacity additions* under RPM, while the smallest

LDAs—PSEG-North, DPL-South, and PEPCO—had 190 MW, 130 MW and 100 MW of *net reductions* in LDA-internal committed capacity.

- Even though the smallest LDAs had net reductions in committed LDA-internal capacity, the total 2014/15 capacity commitments are sufficient to ensure resource adequacy and, in fact, represent an overall surplus relative to the 2014/15 BRA target procurement (shown as a red diamond in the figure, such that capacity above the red dot represents surplus). Target procurement for LDA-internal resources has decreased primarily due to increased import capabilities (CETL).
- Most LDA-internal capacity increases were from demand response, although EMAAC, PSEG-North, and PSEG also had large increases from new generation and uprates.
- Every LDA has had capacity reductions from retirements and capacity derates, and these have been proportionally larger in the smallest LDAs. These capacity reductions were part of the reason that these LDAs have been modeled as constraint under RPM; the reductions also contributed to triggering transmission upgrades that have increased import capabilities into these locations.
- PEPCO, SWMAAC, and EMAAC all retained large amounts of existing generation with high bids above $150/MW-day, primarily related to the cost of retrofits required to meet state and federal environmental regulations implemented or proposed since 2006/07.
- Most LDAs other than DPL-South and PEPCO also show that a sizeable fraction of their existing generation did not clear in the base auction for 2014/15. These uncleared existing resources were not needed for reliability in the most recent auction, partly because of reductions in the load forecast and increases in transmission import limits. Unless they are cleared in future incremental auctions, these resources must be expected to retire.

All LDAs also had uncleared offers for new resources in 2014/15, ranging from 2.3% to 4.3% of installed resources. In LDAs other than EMAAC, 43% to 70% of these uncleared new resources were demand-side resources, with the remaining 30% to 57% from uncleared uprates to existing generation. EMAAC was the only LDA with uncleared new generation in 2014/15 (650 MW). The lack of uncleared offers for new generation in the other LDAs presumably is related to the lack of need and developer cautiousness surrounding the recession and proposed transmission upgrades. It is important to note, however, that there were other uncleared offers for new generation in prior auctions, but these previously-offered new generating plants were not offered for 2014/15. In prior auctions, *all LDAs* had additional uncleared offers for new resources which could have been procured at higher prices had they been needed for reliability.

Table 11
LDA Net Capacity Additions Committed in RPM Auctions

	RTO	MAAC	EMAAC	PSEG	PS-North	DPL-South	SWMAAC	PEPCO
EXISTING CAPACITY IN 2006/07								
Internal Generation	164,914	67,336	33,022	8,129	4,475	1,715	11,639	6,344
Active Load Management	1,679	795	287	121	60	17	227	-
Imports	1,436	-	-	-	-	-	-	-
Exports	(5,274)	(1,549)	(4)	-	-	-	(48)	-
2006/07 FRR Generation	(23,083)	-	-	-	-	-	-	-
Total Capacity in 2006/07	**139,672**	**66,581**	**33,305**	**8,249**	**4,535**	**1,732**	**11,818**	**6,344**
CAPACITY REDUCTIONS								
Retirements	(5,019)	(3,243)	(1,983)	(686)	(629)	(342)	(922)	(790)
Derates	(2,742)	(1,634)	(727)	(448)	(325)	(75)	(697)	(424)
Net Increases in Exports	-	-	(670)	-	-	-	-	-
Net FRR Capacity Removed from Auctions	(6,830)	-	-	-	-	-	-	-
Excused Capacity	(710)	(630)	(24)	(1)	-	-	-	-
Total Reductions	**(15,300)**	**(5,507)**	**(3,404)**	**(1,135)**	**(954)**	**(417)**	**(1,619)**	**(1,214)**
Uncleared Offers for Existing Resources	*(4,958)*	*(1,698)*	*(766)*	*(439)*	*(301)*	*(101)*	*(932)*	*(67)*
RETAINED CAPACITY								
Bids Above $200/MW-d	1,417	1,417	563	257	257	275	853	853
Additional Bids Above $150/MW-d	1,845	1,845	166	-	-	-	1,679	-
Total Prevented Reductions	**3,262**	**3,262**	**729**	**257**	**257**	**275**	**2,532**	**853**
CAPACITY INCREASES								
New Generation	4,750	1,614	1,108	309	291	52	57	2
Uprates	4,088	1,849	1,079	304	101	34	269	206
Reactivations	841	361	151	16	3	-	181	-
Net Reductions in Exports	4,040	875	-	-	-	-	48	-
Net Increases in Imports	2,856	-	-	-	-	-	-	-
ILR & DR Additions (from ALM baseline)	11,006	6,209	2,487	813	369	197	1,935	864
Energy Efficiency	793	193	20	5	-	5	156	42
Total Cleared Increases	**28,375**	**11,100**	**4,845**	**1,446**	**763**	**288**	**2,646**	**1,114**
Uncleared Offers for New Resources	*2,521*	*2,283*	*1,338*	*248*	*101*	*68*	*545*	*234*
Net Committed Capacity Additions	**13,075**	**5,593**	**1,442**	**311**	**(190)**	**(129)**	**1,027**	**(100)**
Installed Capacity Plus Net Additions	**152,747**	**72,175**	**34,747**	**8,560**	**4,345**	**1,603**	**12,845**	**6,244**

Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms
Gross and net changes are BRA and IA capacity commitments (resources offered but uncleared are separately reported).
From PJM bid and resource data, PJM (2007a).

D. Generation Interconnection Queue

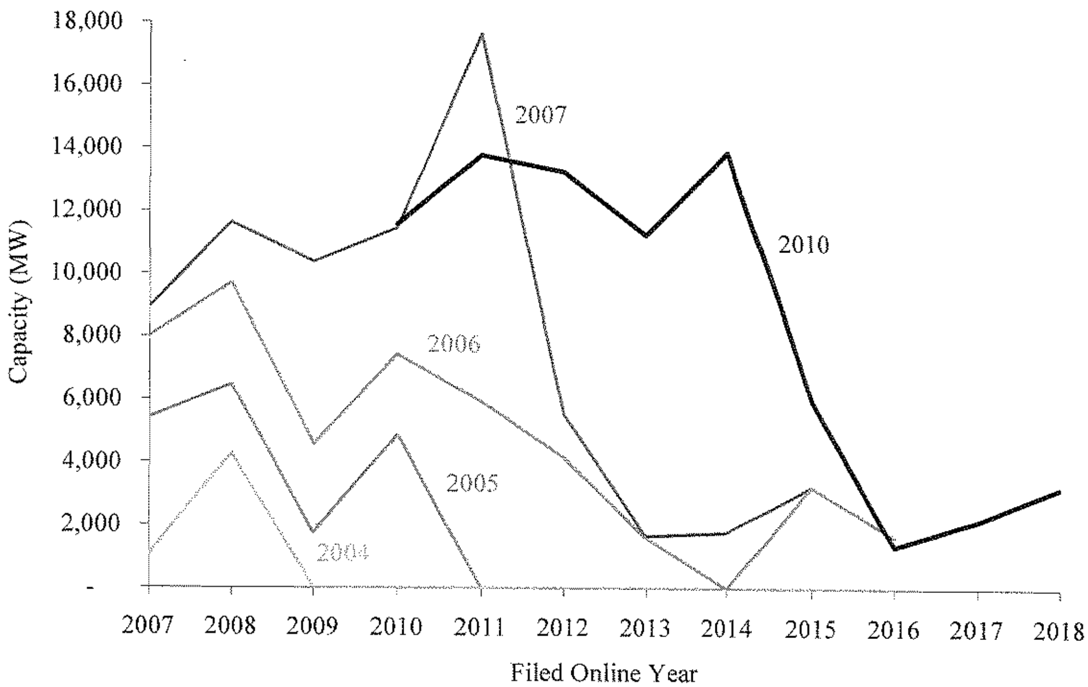
In our 2008 RPM evaluation, we reported that RPM had stimulated the development of an unprecedented amount of potential new resources, including approximately 33,000 MW of new generation projects in PJM's interconnection queue that were eligible to offer into future RPM auctions, with capacity that was not already committed as the result of the first five base auctions. Approximately 28,000 MW of this capacity was from non-renewable resources for which RPM-based capacity payment are likely a major driver.[53] We also documented that a significant expansion in interconnection requests had occurred by 2007, and we observed a spike

53 2008 RPM Report, pages 38-39

in interconnection requests with an online date of 2011, just in time for the first 3-year forward auction for the 2011/12 delivery year.

Figure 13 below shows interconnection requests for the period from 2004 through 2007, updated with queue data from 2010, as summarized by the IMM. The total capacity of generation projects submitted in the queue as of 2010 remains high despite the economic downturn, reductions in load forecasts and associated reliability requirements, and significant expansion of capacity from demand-response resources. In addition, the pattern we previously observed has been maintained despite the fundamental economic changes since 2007: at the end of 2010, just prior to the BRA auction for the 2014/15 delivery year, the interconnection queue shows a similar spike of interconnection requests with an online date of 2014.

Figure 13
Capacity of Active Generation Projects in Interconnection Queue
(2004-2007 and 2010, by online date)



Source: 2005-2007, 2010 PJM State of the Market Reports.

Table 12 shows total unforced capacity (*i.e.*, derated to the resources' capacity value) of active interconnection requests currently in the PJM queue by LDA. As shown, generation projects in the interconnection queue that have already passed the feasibility study and, thus, qualify to be bid into RPM, have remained high compared to needs at both the RTO and LDA levels. Interconnection requests with over 26,000 MW qualify for RPM participation the RTO-wide level, 13,000 MW of interconnection requests qualify in MAAC, 3,100 MW in SWMAAC, 1,400 MW in PEPCO, 7,300 MW in EMAAC, 1,900 MW in PSEG, and 500 MW in DPL. We recognize that the status of the projects behind these interconnection requests is generally uncertain, and the same generation project may be represented in multiple interconnection

requests.[54] However, the number of interconnection requests, their aggregate capacity value, and their locational distribution suggest that sufficient new generating resources stand ready to be developed if market conditions warrant such additions and development challenges can be overcome.

Table 12
Planned Projects Eligible for RPM Participation

Locational Deliverability Area	TOTAL RPM QUALIFIED MW	TOTAL UNDER STUDY MW
DPL	500.2	1,751.8
PSEG	1,932.1	4,274.0
EMAAC	7,318.7	12,730.6
PEPCO	1,453.8	2,283.8
SWMAAC	3,093.8	3,923.8
MAAC	12,980.8	22,570.2
Unconstrained RTO	13,564.7	21,665.3
RTO TOTAL	**26,545.5**	**44,235.5**

Sources and Notes:
[1] PJM queue data downloaded on 8/15/2011.
[2] Quantities are calculated based on net summer capacity (wind and solar derated to capacity value).

Our 2008 RPM report identified delays in the interconnection process as a significant concern.[55] At that time, PJM had accumulated a substantial backlog of overdue interconnection studies in its interconnection process, following a surge of interconnection requests in response to the implementation of RPM and state renewable portfolio standards.

To improve the interconnection study process, PJM reconvened the Regional Planning Process Working Group and implemented a number of changes to streamline the interconnection process.[56] The most significant accomplishments are:

- PJM introduced three-month queue cycles. As a result, System Impact and Feasibility Studies are now conducted in four cycles per year (as opposed to two cycles per year previously).

[54] For example, the 3,100 MW of RPM-qualifying interconnection requests in SWMAAC include a new 1,640 MW nuclear plant in the BG&E service area which, even if developed successfully, would not become available in time for the next several BRAs. Similarly, the PEPCO queue includes interconnection requests for two 725 MW combined cycle plants in the same county, which likely represent overlapping interconnection requests from the same projects. However, even a single 725 MW CC plant built in PEPCO would satisfy load growth-related resource adequacy needs for many years.

[55] Section V.B.

[56] Interconnection Process Changes and Timetable, presented at RPPWG in March 2009, http://www.pjm-miso.com/committees/working-groups/rrawg/downloads/20090116-item-03-changes-and-dates.pdf

- In order to reduce the number of non-viable projects and multiple interconnection requests submitted for speculative purposes, PJM began requiring deposits that increase each month during the queue and include both a refundable and a non-refundable element.
- In the past, PJM often received a large number of interconnection requests at the end of the queue period, which significantly contributed to the backlog in the queue. Under the revised rules, the timeframe allowed for holding a scoping meeting to initiate interconnection studies decreases the later a request is entered into the queue, thus providing an incentive to submit interconnection requests earlier in the queue cycle.
- Interconnection requests must now specify a primary and a secondary interconnection point. In the past, interconnection customers could choose two points of interconnection, and PJM was required to conduct two simultaneous sets of studies for each of the two locations.
- PJM revised the methodology of allocating the costs of required transmission upgrades. In the past, cost allocation was determined incrementally, based on the position in the queue. As a result, PJM had to perform repeated studies whenever an earlier project in the queue was withdrawn. Under the new method, PJM performs studies in clusters and analyzes all projects in a single queue.
- Other changes include requiring timelier submittal of necessary data, applying commercial probability of success ratios at various stages of the interconnection process, and requiring proof of site control.

While the interconnection process continues to be a source of uncertainty for generation development, particularly with respect to interconnection costs, PJM has made significant progress streamlining the process. Queue requests are now processed in a timelier manner. As shown in Table 13 below, 89% of Feasibility Studies were issued on time in 2010.[57] This is a significant improvement since 2007, when only 53% of Feasibility Studies were completed on time. Similar improvements have occurred with respect to System Impact Studies: while in 2008 only 29% have been completed on time, that proportion had increased to 77% as of 2010.

Table 13
Percentage of Interconnection Studies Completed On Time

Year	Feasibility Study	System Impact Study
2007	53%	44%
2008	70%	29%
2009	83%	51%
2010	89%	77%

Source : PJM

PJM's corporate goal for 2011 is to complete all studies backlogged as of January 1, 2011 by the beginning of 2012, and to reduce the backlog of System Impact and Feasibility Studies below

[57] These studies represent two of the main steps in the interconnection process.

25% and 10%, respectively.[58] To address the remaining challenges related to the interconnection process, PJM formed the Interconnection Process Senior Task Force ("IPSTF") in February 2011. IPSTF's goal is to develop enhancements that would lead to more consistent and realistic interconnection cost estimates, more timely completion of interconnection studies, and greater transparency of the overall interconnection process.

E. Summary of Findings from Auction Results

After completing auctions for eight delivery years under RPM, the market has thus far achieved its design objective of procuring sufficient capacity to meet reliability requirements. A total of 28.4 GW (ICAP) of gross additions and 13.1 GW of net additions have been added or committed under RPM auctions (excluding FRR and RTO expansions), exceeding reliability requirements. The gross committed additions are from 11.8 GW of new demand resources, 6.9 GW of increases in net imports, 4.8 GW of new generation, 4.1 GW of uprates, and 0.8 GW of reactivations. These additions were offset by 15.3 GW of gross capacity reductions, including 5.0 GW of retirements, 2.7 GW of derates, 6.8 GW of capacity removed from auctions for FRR, and 0.7 GW of generation excused from auctions.

On both an RTO and LDA-specific basis, sufficient capacity was procured under RPM to meet or exceed the reliability targets, with no large or persistent capacity deficits observed to date. Procurement below the reliability target in eastern LDAs during the first years under RPM was related to the overall tight supply conditions that existed prior to the introduction of RPM. All LDAs also had additional uncleared offers from incremental capacity supplies in most years that could have been procured at higher prices had those supplies been needed for reliability.

To date, RPM has performed well in the face of the proposed EPA HAP regulation, which will take effect during the 2014/15 delivery year and impose large compliance costs on many coal generators and force others to retire. Despite this substantial challenge to resource adequacy, capacity procurement through the 2014/15 delivery year exceeded the target procurement on an RTO-wide level as well as in all modeled LDAs. Due to environmental regulations and an overall capacity surplus, 12.8 GW (ICAP) of existing capacity, mostly coal, is currently uncommitted for resource adequacy in 2014/15, having been withdrawn from RPM auctions or failed to clear the BRA. Many of these generators would need to invest in environmental upgrades to continue operating in 2014/15 and will likely retire if they do not clear in upcoming auctions.

Clearing prices in the base auctions have been consistent with market fundamentals—clearing at levels below Net CONE during times and locations of capacity excess and above Net CONE at times and locations of relative scarcity. Large quantities of relatively low-cost capacity additions from DR, uprates, and increased net imports have kept prices below Net CONE most of the time in most locations. These increases in low-cost resources have reduced system costs by postponing the need for expensive additions of new generation and allowing for the retirement of uneconomic existing capacity. Furthermore, the supply curves have become more gradual due to the incorporation of substantial quantities of DR and the three-year forward period of RPM, which will contribute to increase price stability in the future. To date, base auction prices have

[58] For example, see "Interconnection Update," February 16, 2011. http://www.pjm.com/~/media/committees-groups/committees/mrc/20110216/20110216-item-06a-interconnection-update.ashx

been somewhat volatile, with substantial price changes from year to year caused by market fundamentals, changes in market rules, changes to which LDAs were modeled, and changes in administrative auction parameters.

Clearing prices in the incremental auctions prior to the 2012/13 redesign demonstrated a pattern of being persistently far below base auction clearing prices. However, as discussed in Section II.B, the incremental auction design has been substantially improved starting with the 2012/13 delivery year. Initial results show that the new design resulted in prices that are more consistent with base auction prices, though more experience with the new design is needed to fully understand how it will function over time.

III. STAKEHOLDER COMMENTS AND DISCUSSION OF KEY THEMES

As an initial task in our RPM performance review, we gathered input on which aspects of RPM are working well and which should be improved. We gathered input from five stakeholder sectors, financial analysts, public utility commissions, and the Independent Market Monitor.

Stakeholder Sectors — We conducted sector interviews with transmission owners, generation owners, electric distributors, end use customers, and other suppliers. Stakeholders have also provided 13 sets of written comments and several have contacted us for individual follow-up interviews.

Financial Analysts — We individually interviewed financial analysts covering RPM from CitiGroup, UBS, and Goldman Sachs.

State Utility Commissions — We contacted members of each public utility commission of 13 states and the District of Columbia. In response, we received input in interviews or written comments from eight commissions (Delaware, the District of Columbia, New Jersey, Ohio, North Carolina, Pennsylvania, Michigan, Virginia). The remaining six commissions either declined to comment (Maryland and Kentucky) or did not respond (West Virginia, Tennessee, Illinois, and Indiana).

Independent Market Monitor — We reviewed the substantial body of evidence and analysis on RPM that has been developed by the independent market monitor (IMM), including the state of the market reports, auction reports, and comments in FERC and state proceedings.[59] We have also had several conference calls and exchanges with the IMM to discuss our recommendations and analysis related to specific elements of the RPM design.

We summarize here stakeholders' comments and identify the key themes that have emerged, which we used to focus our analysis on the topics most important to stakeholders. We respond to each of the most prominent themes here and explain how we have addressed each of them in the body of this report.

[59] See reports posted at www.monitoringanalytics.com.

A. Summary of Stakeholder Comments

A detailed summary of stakeholder comments is included in the Appendix. We summarize here the topics that were stressed as the most important issues that we should consider in our performance review.

Level of RPM Clearing Prices — End use customers and state commissions in eastern PJM stated that RPM prices were too high and may not be commensurate with the value of reliability to customers. Some commissioners further stated that existing generation and demand resources should be paid lower prices than new generation. Generation and transmission owners stated that eastern prices are not high enough to attract new investments, while western prices are too low and are creating retirement incentives. Other suppliers noted that incremental auction prices are biased to be much lower than BRA prices.

Uncertainty of RPM Prices — All stakeholder sectors stated that RPM prices are volatile and too difficult to predict. However, generation and transmission owners also indicated that RPM price signals are more stable and locationally appropriate compared to prices in PJM's previous daily capacity market. Financial analysts stated that investors discount the value of RPM revenues due to the uncertainty and that more transparency is needed in the supply curve and administrative calculations to allow for improved projections that would better support investment decisions.

Capacity Additions and Retention — Concerns about a lack of new generation entry were expressed by eastern state commissions, electric distributors, end use customers, some generators, and some transmission owners. Other generators and transmission owners stated that fears of a capacity shortage were overstated and that new investments can be financed when prices are high enough, although more capacity price stability and longer-term hedging mechanisms would help. Generation and transmission owners point out that the EPA HAP regulation will create a resource adequacy challenge and force many plants into retirement.

Reliability Standards and Customer Reliability Requirements — End use customers and state commissions stated their belief that PJM has an institutional bias to overstate load forecast and reliability requirements, causing excess costs to customers. They further question whether the 1-in-10 system reliability standard and in particular the 1-in-25 LDA transmission-contingent reliability standard are appropriate, suggesting that they represent too much reliability given the high cost of capacity. End use customers are further concerned about significant quantity risks that they face due to substantial uncertainties about their ultimate Peak Load Contribution ("PLC") and the slope of the VRR curve, which also makes it difficult and risky for individual large end-users to directly participate in RPM as a demand-response resource.

Cost of New Entry — End use customers stated that CONE should be based on the lowest net cost technology in each region. Generation and transmission owners argued that CONE is understated because of cost estimates that are too low for natural gas interconnections, transmission interconnections, labor, taxes, and financing costs.

Energy Market and E&AS Offset — Electric distributors, other suppliers, transmission owners, generation owners, and state commissions noted that they support greater scarcity pricing in the energy market. Other suppliers and electric distributors stated that

the current energy market price cap of $1,000/MWh is too low and creates a disadvantage for DR in the capacity market, especially as an annual resource, because they may value the energy at a higher rate. Generation and transmission owners stated that there should be no capacity payment reductions due to scarcity pricing other than incorporating scarcity prices into the E&AS offset as is currently done. End use customers stated that the lag in the historical E&AS offset will be especially problematic during the transition to scarcity pricing. Other suppliers and financial analysts stated that the E&AS offset should be forward looking, while transmission owners stated that a forward-looking offset would be prone to error and dispute. Generation owners, other suppliers, and transmission owners stated that the calculated E&AS offset was too high given the current low gas prices and energy margins, the use of real-time rather than day-ahead prices, and an optimistic dispatch algorithm.

VRR Curve and FRR Alternative — Generation owners, other suppliers, and transmission owners stated that the VRR curve is too steep and causes price volatility. State commissions stated that the 1% adjustment to point "b" on the curve creates a bias toward over-procurement. State commissions and transmission owners stated that the FRR alternative is valuable but that restrictions on capacity sales and switching to or from FRR should be relaxed.

Demand-Side Resources and Resource Comparability — Generation and transmission owners expressed the concern that lax performance and qualification standards threaten the quality of the capacity procured from demand resources. They further stated that demand resources have fewer obligations than does generation supply, including the lack of a must-offer requirement in the energy market. End-use customers and other suppliers noted that demand resources are disadvantaged due to high credit requirements and risks in the three-year forward BRA. The independent market monitor suggested that all resources should have the same obligations and the same definition of capacity.

2.5% Short-Term Resource Procurement Target — The IMM, generation owners, and transmission owners recommended that the 2.5% "holdback" be eliminated because it artificially suppresses BRA prices. Electric distributors stated that the 2.5% holdback should be maintained, while other suppliers noted that the holdback is too small and artificially inflates BRA prices while suppressing incremental auction prices. End-use customers stated that, with only one incremental auction since the implementation of the holdback, there was not enough information to evaluate the appropriate size of the STRPT amount.

Transmission-Related Issues — Comments on transmission issues did not generally differ across sectors, although multiple views were often expressed within each sector. Stakeholders identified CETL as an important parameter that is volatile and not transparent. Most sectors suggested that major transmission projects should not be cancelled so readily and that RTEP should more fully consider economic criteria in addition to reliability criteria. Stakeholders indicated that greater consistency is needed between RTEP and RPM, including making sure that uncleared RPM resources are not modeled in RTEP. Some stakeholders argued that additional LDAs should be modeled including part of Dominion or APS-South, or that all 23 LDAs should be modeled. Other stakeholders argued that too many LDAs already exist, that LDA are modeled even when no longer constrained, and that only 2 or 3 LDA may be necessary. Transmission and

generation owners suggested that the BRA should be conducted on a 5-year forward basis to coincide with RTEP planning horizons.

Market Monitoring and Mitigation — Electric distributors and state commissions stressed that new MOPR provisions will have the large unintended consequences of eliminating self-supply and creating excess risks for new generation developments. Financial analysts, generation owners, and transmission owners emphasized that MOPR must be strong enough to prevent market manipulation through state-sponsored capacity additions. The independent market monitor is also concerned about out-of-market capacity additions, but recommends an exemption for procurement through competitive, non-discriminatory processes. End use customers noted that they are concerned that bid adders allowed under the avoidable project investment rate ("APIR") may be too high and allow for economic withholding, which may be a particular concern as suppliers are forced to comply with EPA's HAP regulations.

Extending Forward Certainty — Stakeholders representing both buyers and suppliers of capacity noted a lack of sufficient long-term contracting. Electric distributors, end-use customers, and generation owners attributed the lack of bilateral long-term contracting to state retail choice and standard offer service programs. Generation owners noted that there is a lack of buyers for long-term bilateral contracts with durations of more than 3-5 years, while electric distributors have stated that they are unable to find suppliers willing to enter into bundled long-term energy and capacity contracts. All stakeholder sectors suggested options for extending forward certainty and providing hedging options under RPM. These options included a continuously-clearing over-the-counter ("OTC") market for capacity and longer-term procurement through multiple forward or strip auctions. Generation and transmission owners were divided on NEPA, with some stating that the mechanism is discriminatory and should be eliminated and others stating that it should be expanded to existing generation, extended in duration, or applied outside the LDAs. Financial analysts stated that extending NEPA would benefit project financing.

We used these stakeholder comments and concerns to focus our performance review on the topics of highest importance. We recognize that many of these comments represent conflicting viewpoints between sectors and sometimes even within individual sectors, but have attempted to evaluate all of the associated arguments. Stakeholders identified concerns with a number of specific design elements, but we also identified a few key themes of several inter-related issues. To help clarify some of these more general concerns, we discuss them in the remainder of this section and note if we have analyzed and addressed them more fully later in this report.

B. Capacity Price Volatility and Uncertainty

The greatest concern expressed by stakeholders from all sectors is that capacity prices under RPM are highly volatile and very difficult to predict. Stakeholders express that this uncertainty imposes additional costs and creates difficulty hedging and making investment decisions. Some stakeholders have expressed a lack of transparency about the underlying causes of major price changes, or have attributed various price changes to causes that they view as arbitrary or inefficient.

In response to these stakeholder concerns, we have reviewed all substantial price changes observed under RPM to date. We have identified and documented the major drivers behind the

observed price changes as explained in Section II.A (for the BRA) and Section II.B (for the incremental auctions) of our report. These main drivers of capacity price uncertainty fall into three categories: (1) underlying market fundamentals; (2) RPM design elements that have previously caused significant price adjustments; and (3) current RPM design elements and related administrative parameters that cause significant price uncertainty.

Ideally, only market fundamentals should drive capacity prices or create price uncertainty, factors which should not be dampened by RPM design or administrative intervention. In fact, administrative and regulatory uncertainty, while impossible to eliminate, should be minimized to the extent practical. We briefly discuss each type of uncertainty in the remainder of in this section and more fully address options to mitigate excess price risks related to administrative factors in our discussion of specific RPM design elements.

1. Market Fundamentals

Several changes in underlying market fundamentals have been major drivers of price changes and uncertainty:

- The emergence of surplus capacity in the unconstrained RTO, and to a lesser extent in the LDAs, that has depressed capacity prices to levels well below Net CONE;
- Transmission constraints between the unconstrained RTO and the LDAs have limited the ability to import low-cost supply into eastern PJM and caused large locational price separations in some years;
- Steep supply curves during the first RPM auctions caused prices to be sensitive to small changes in resource demand. The steep supply curves were primarily the result of a short forward period (*i.e.*, less than 2 years) between the auction and delivery year for the first several RPM auctions. This limited the potential quantity of new capacity that could participate in the auctions and be available in time for the delivery year. Supply curves have since flattened significantly, due to the longer forward period and a substantial influx of DR resources with offers covering a wide range of prices;
- Significant growth in low-cost DR resources has contributed to lower prices;
- The economic recession has reduced the outlook for electric demand starting with PJM's 2009 load forecast used for the 2012/13 BRA; and
- Environmental upgrades that will be required by the EPA HAP regulation for operation sometime in during the 2014/15 delivery year have caused prices to rise substantially in the unconstrained RTO in the most recent BRA.

All price uncertainty and volatility will tend to increase risks and therefore increase costs.[60] However, to the extent that these risks consistent with uncertainty in underlying market fundamentals, they are important to ensure the efficient functioning of the market and should not

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[60] Increased risks of all kinds result in a higher expected required return on investments. See, for example, the empirical finding that "a doubling of industry-wide uncertainty raises the required rate of return on new capital by about 20 percent," by Caballero and Pindyck (1996). For another example, see the empirical finding that increased volatility in cash flows increases the cost of debt and decreases the likelihood of making investments from Minton and Schrand (1999), pp. 423-26.

be suppressed artificially. Stabilizing RPM prices despite underlying uncertainties in market fundamentals would not eliminate the associated risks, but would simply shift the costs associated with these risks from suppliers to customers. For example, a traditional regulatory regime would reduce a generation supplier's development costs by ensuring cost recovery for all prudent investments, but this does not eliminate the fundamental risk that an event like a major recession could render the investment uneconomic. In a traditionally regulated environment, the out-of-market costs of the uneconomic investment would be borne by customers paying for unneeded supplies. In a restructured, competitive wholesale power market like PJM, however, the suppliers bear the market risk of losing money on uneconomic investments.

One of the key benefits of competitive power markets, including the PJM's capacity market, is that market prices can move with market fundamentals and create incentives to respond. Unexpectedly high prices will create a strong incentive for suppliers to quickly develop more demand response and speed the completion of generation under construction. Similarly, unexpectedly low prices will signal that expensive existing generation should be retired and new generation projects should be delayed. Ensuring that these incentives are delivered accurately to marginal resources through capacity prices will allow reserve margins to remain near the target levels, preventing both severe shortages and costly excess of supply. Private investors facing the risks associated with these market fundamentals will carefully assess the likelihood that their investment may become uneconomic and incorporate that possibility into their investment decisions.

Market rules or administrative interventions that dampen these price signals will tend to create an inefficient disconnect between market fundamentals and incentives.[61] For this reason, we are skeptical of some options for reducing RPM price uncertainty, including the further flattening of the VRR curve (as discussed in Section V) or expanding the New Entry Pricing Adjustment (NEPA) mechanism (as discussed in Section VI.F). However, while we recommend that RPM clearing prices should be allowed to continue to reflect changing and sometimes volatile market conditions, this does not mean that market participants should not have opportunities to hedge against these risks. These hedges may take the form of asset ownership or bilateral contracts (as discussed further in Section III.C) or may include other options for facilitating long-term hedging options through RPM design (as discussed further in Section VI.F).

2. Previously-Changed RPM Design Elements

Some of the RPM prices and price changes observed to date were caused by unintended consequences of market design elements that have since been modified. These previously-addressed modifications to RPM design elements include:

61 For example, the price floor in ISO-NE's forward capacity market (FCM) has created substantial price stability in that prices have cleared at the floor for the first five forward capacity auctions. However, this stability has come at the cost of exacerbating an over-supply situation by preventing expensive existing generation from retiring and attracting substantial new supplies into the market. In fact, the first FCA for 2010/11 cleared at the floor with 1,772 MW of excess capacity, while subsequent auctions cleared at the price floor with increasing excesses of up to 5,374 MW for 2013/14 before dropping to somewhat lower levels for 2014/15 in the face of the EPA HAP regulation. See ISO-NE (2011a) and (2011b), p. 106.

- When RPM was implemented, a large portion of demand-side resources was interruptible load for reliability (ILR), which was accounted for outside the RPM auctions. This meant that auction prices initially failed to reflect the substantial growth in demand-side resources. Incorporating these resources into the auctions starting in the 2012/13 BRA allowed auction prices to reflect these supply fundamentals more accurately, which resulted in a large price drop (mostly in the unconstrained RTO) compared to the previous years.[62]

- For the first five delivery years, the rules governing which LDAs would be modeled in RPM auctions were more restrictive. This resulted in frequent changes in which LDAs were modeled and were allowed separate from the RTO and other LDAs in terms of its clearing price. In some cases this prevented price separation that would have been necessary to reflect market fundamentals as discussed in Section II.A. A set of rule changes implemented in time for the 2012/13 BRA ensured that certain LDAs were modeled, which allowed prices to separate. Going forward, these rule changes will create more stability in which LDAs are modeled and will allow LDAs that might price separate to be modeled more often.[63]

The unintended consequences associated with these RPM design elements resulted in a failure to fully account for demand-side resources and transmission constraints, which led to higher auction prices. Adjusting these design elements caused some of the observed price changes, but resulted in an improved market design with better price signals going forward. We keep these previous changes in RPM design elements in mind as we evaluate related aspects of RPM, because it will be valuable to avoid similar unintended consequences in the future. In particular, we examine the importance of modeling additional LDAs that might price separate in the future (Section VI.A) and examine the potential future implications of incorporating multiple demand response products (in Section VI.C).

3. Current RPM Design Elements and Administrative Parameters

While some market design elements (or adjustments to them) have created price volatility in the past, Stakeholder groups have identified several market design and administrative parameters that are quite uncertain and, as a result, continue to create significant uncertainty in RPM prices beyond changes in market fundamentals. We have identified two sets of design elements and administrative parameters that result in significant capacity price uncertainty:

- *Volatility and uncertainty in CETL*, which determines the quantity of capacity that can be imported into each LDA. Some changes in CETL are driven by changing plans for major transmission upgrades. Other changes are driven by modeling sensitivity to detailed assumptions including load distribution and the forecast of generating units are expected to be online or retired.

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[62] See PJM (2011d), sections 4.3.5 and 9.3.6.

[63] Prior to 2012/13, LDAs were modeled only if their Capacity Emergency Transfer Objective ("CETO") was ≤ 1.05 CETL. Starting with 2012/13 more LDAs will be modeled, including: (1) MAAC, SWMAAC, and EMAAC which will always be modeled; (2) LDAs with CETO ≤ 1.15 CETL; (3) LDAs that have price separated in any of the three previous BRAs; and (4) any LDAs that PJM expects may price separate. See PJM (2011d), pp. 11-12.

- *Changes in the load forecast and locational reliability requirements.* Some changes in the load forecast and associated reliability requirements are driven by market fundamentals including the recent economic recession. However, other changes may be related to forecasting uncertainty or related changes in administrative assumptions.

These market design issues are primarily related to the difficulty of determining administrative parameters that are inherently uncertain but that have a large price impact on auction prices. One reason that these parameters are so uncertain is that they are related to future market fundamentals that cannot be accurately predicted by market participants or by PJM. However, some of the uncertainty and the impact that these administrative uncertainties have on market prices can be reduced in several ways, including: (1) improving market participants understanding of the uncertainty in these parameters; (2) increasing transparency by providing and more frequently updating the long-term outlook for administrative parameters; (3) reducing the sensitivity of final RPM auction parameters to modeling assumptions; and (4) limiting the impact of changes in administrative calculations on auction results.

We examine several of these options in Section VI.B with respect to load forecasting and reliability requirements and in Section VI.A with respect to CETL and transmission upgrades.

C. The Lack of Long-Term PPAs to Support New Plant Financing

A number of stakeholders have expressed concerns related to an apparent lack of long-term contracting that could support the financing of new generation additions in eastern PJM:

- Regulators in eastern PJM expressed the concern that there is a dearth of new power plant construction under RPM.
- Some generation developers similarly noted that three-year forward RPM prices effective for only one delivery year do not support the financing of new generation projects. They suggest that prices would need to be locked in for up to 10 years or more to support financing of new generation projects.64
- Financial industry participants similarly note that RPM does not support the financing of new generation, which would require revenue certainty over longer periods of possibly 10 years or more.65
- Stakeholders universally reported a current lack of long-term bilateral contracting of more than three to five years forward to provide price certainty beyond that offered directly by RPM. Generation developers stressed that buyers are unwilling to enter long-term contracts, while stakeholders from the public power companies indicated a strong interest in signing long-term contracts, but stated that they were unable to find willing suppliers.

The concerns that longer-term pricing arrangements are needed for financing new plants are seemingly inconsistent with public power stakeholders' concern that suppliers were generally

64 We note that this view is not uniform in the generation owner sector.

65 See also letters from Credit Argicole and Union Bank attached to LS Power Associate Comments on New Jersey Electric Power and Capacity Needs, Submitted in State of New Jersey Board of Public Utilities, Docket No. EO 09110920, July 2, 2011.

unwilling to offer long-term contracts. We believe this apparent inconsistency of concerns is explained largely by current market fundamentals.

The main reason for the low activity of new power plant construction in eastern PJM is the fact that new plants are not needed for several more years due to a combination of low load growth on the demand side of the market, and lower cost supply options such as deferred retirements, transmission upgrades, demand response penetration, and upgrades to existing units. That is, RPM has been able to retain or attract the lowest-cost set of resources to maintain resource adequacy. In other words, the lack of feasible long-term contract offers for new generation is explained by market prices for capacity that are below the cost of new plants.

These market fundamentals also explain the lack of long-term contracts with existing generation. Suppliers of existing capacity are unwilling to enter long-term contracts at low current prices because they expect prices will rise. At the same time, buyers are unwilling to pay higher prices or even the cost of new generation when there are less expensive options currently available in the market. It is likely, however, that interest in longer-term contracting will increase as excess capacity diminishes and capacity market prices rise to the cost of new generation on average over many years.

It is also possible, however, that secondary factors create contracting barriers, such as the structure of default service procurement in retail access states. If these barriers turn out to be significant—which is difficult to determine under current market conditions—modifying how default service procurement is regulated at the state level may be the most effective way to address these barriers. If that is not feasible, it may be worth considering longer-term pricing options under RPM. We stress caution in considering these options, however, because we believe that it should not be the role of an RTO to offer or force long-term contracting for capacity resources when load-serving entities do not see the risk management benefit of entering into such contracts bilaterally. Nor would an RTO be able to readily determine the amount of long-term contracting or contract terms that optimally balance risks. Mandating too much long-term contracting would inefficiently expose suppliers to delivery and credit risks while buyers are exposed to larger risk premiums and the potential for stranded costs.

It is also likely that the need for and reliance on long-term power purchase agreements (PPAs) and project financing will diminish as the industry evolves and an increasing share of new plants are developed by larger, partially vertically-integrated companies with load serving responsibilities, a portfolio of merchant generation, and sufficiently strong balance sheets to finance the needed investments. We discuss each of these points in more detail in the remainder of this section.

1. The Role of Current Market Fundamentals

It is correct that relatively few new power plants have been built in eastern PJM since RPM has been implemented. However, as we have explained in Section II, it is not true that no new generation has been built in eastern PJM. Even without considering capacity uprates of existing plants (2,210 MW), reactivations (360 MW), export reductions (930 MW), or increased demand response (6,550 MW), approximately 2,040 MW of new generation capacity has been committed in the MAAC region under RPM, and another 650 MW of new generation offers have been

submitted but failed to clear because sufficient capacity has been offered at prices below the cost of new generation.[66]

Nevertheless, the relatively modest level of new generation construction in eastern PJM has not led to resource adequacy shortfalls, as some stakeholders believe. Reserve margins have remained at or above target levels, due to the combination of entry by these new generation units, combined with demand response resources, upgrades to existing capacity, deferred retirements, planned transmission upgrades, and the economic slowdown. Moreover, RPM has maintained resource adequacy at prices that have generally remained below the cost of new generating plants.

It is also correct that market prices for capacity in eastern PJM have been significantly higher than in the remainder of PJM in most years. However, even these eastern PJM capacity prices have generally remained below the cost of new plants in the recent BRAs. Prices will remain below the cost of new plants until new generation is needed and capacity prices rise to clear new offers.

We believe the underlying fact that new generation is simply not cost-competitive with lower cost options such as uprates, deferred retirements, and demand response under these market fundamentals is the primary reason that there has not been more new construction of generating plants in eastern PJM. That capacity prices will remain below the cost of new plants through 2014/15 and possibly for several more years is likely also the primary reason that some developers' new generation projects cannot be financed without long-term contracts. Current market conditions do not support long-term contracts at prices high enough to finance new plants because rational buyers prefer to satisfy their capacity requirements at market prices that are below the contract cost of a new plant.

Under these market conditions, when few or no new plants are needed, the only way to finance additional new generation would be through above-market long-term contracts. Such above-market contracts have recently been offered through a New Jersey legislative mandate, which procured capacity for three new plants under fixed-price 15-year contracts whose costs are not public but that are estimated at approximately $270-350/MW-day.[67] In comparison, RPM prices in New Jersey have been much lower at $136-225/MW-day for annual resources in the most recent BRA.

In short, the lack of long-term contracts and financing for new plant construction is a consequence of the fact that investments in new generation are at present inherently unprofitable and not part of the least-cost solution to resource adequacy. Currently, new generation is not a cost effective way to meet anticipated load growth. Under these circumstances we do not expect a well-functioning market to reward investments in new generation. In other words, the absence of new construction is a sign that the market is working.

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66 Reported in ICAP. Note that most new generation offers that have failed to clear in one auction have subsequently offered and cleared in later auctions, from PJM (2011a).

67 See

Table 1 for auction prices. Approximate New Jersey procurement prices were calculated by the New Jersey EDCs (2011), pp. 8-9.

Current market fundamentals are also the likely reason that public power entities looking for long-term capacity contracts have not found willing suppliers. First, given that capacity prices may remain below the cost of new plants for a number of years, buyers interested in long-term contracts will not be willing to sign long-term contracts priced at the full cost of new power plants. Thus, developers of new power plants will be unwilling to offer long-term contracts at prices acceptable to buyers. Second, even owners of existing generating capacity will be unwilling to sign long-term contracts at prices equal to current market prices if they anticipate that RPM prices increase over time. It is likely, however, that buyers' and existing generators' interest in longer-term contracting will increase as excess capacity diminishes and capacity market prices rise to the cost of new generation over the next several years.

2. Availability of Financing

As discussed, current market fundamentals in PJM do not generally support the entry of new plants. Thus, without a need for new plants, financing for such plants will not be available unless supported by (above-market) long-term contracts.[68] However, this does not mean that financing is not available for sound investments at costs that are consistent with market fundamentals. In fact, there has been keen interest in the acquisition of power plants in eastern PJM, and major recent transactions have documented the availability of financing for investments in merchant power plants.

A notable example in eastern PJM is Calpine's 2010 acquisition of 4,490 MW of Conectiv Energy power plants in eastern PJM from Pepco Holdings Inc. ("PHI").[69] The $1.63 billion purchase, which included some existing forward capacity and energy sales commitments as well as a six-year tolling agreement with Constellation Power for the Delta power plant that was under construction at the time, was financed with $1.3 billion of seven-year debt and $100 million of three-year debt.

3. The Role and Implications of "Project Finance"

Generation developers' frequent preference to build new power plants through highly-leveraged "project finance" arrangements appears to be another major driver behind their interest in long-term power purchase agreements. Project finance refers to the use of project-specific debt, also called "non-recourse" debt that is not backed by a guarantee from a larger parent company. Project finance is often the only available option for small project development companies that do not have a significant portfolio of other assets or for companies with weak balance sheets and poor credit ratings.

Such non-recourse debt is secured solely by the revenues and asset value of the specific power plant. It is more risky to the lender and consequently more expensive than corporate debt that is secured by the more diversified revenues and assets of the parent company. However, while more expensive than corporate debt, non-recourse debt is still attractive to developers because it

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68 See also B. Chin, "Capacity Issues Technical Conference: State of New Jersey," Citi Investment Research, June 24, 2010, noting that "in our view, energy/capacity markets are providing a signal that capital should not be deployed to [new] generation at this time, unless subsidies are enacted."

69 For example, see Calpine (2010).

is less expensive than equity and reduces the potential liability to the parent company if the project proves to be a bad investment.

To reduce financing costs, project developers will similarly prefer to "lever up" their investments by using higher levels of debt and less equity. However, such reductions in financing costs are possible only if project risks are reduced through long-term power purchase agreements that shift market risks from the generation owner to the buyer of the power. In fact, by assuming project risks through a long-term contract, the buyer is reducing (and essentially subsidizing) the financing cost of the new plant. Financing projects with high levels of debt (*e.g.*, 70 to 80% debt) can reduce the levelized annual investment cost of a project by 10% to 20% compared to merchant plant financing, which may allow financing with only 30% to 50% non-recourse debt (backed solely by the project) or 50% to 60% corporate debt (backed by the entire parent company).

In a well-functioning market, a range of financing arrangements will exist under which buyers can assume risks under a long-term contract (that support for more highly leveraged financing by the developers) or developers can assume these risks (which requires financing with more equity) depending on risk sharing preferences and the financial conditions of the counterparties. However, it is not desirable to enable uneconomic investments in new generation through long-term PPAs when those developments are more costly or more risky than capacity from market-based resources, including from existing generation supplies and demand response.

4. The Role of Default Service Procurement in Retail Access States

We believe that longer-term contracting will increase as capacity market prices reach and sometimes exceed the cost of new generation. It is conceivable, however, that market or regulatory barriers could prevent an outcome in which an efficient level of longer-term contracting is achieved, although we do not presuppose to know what that efficient level of long-term contracting might be.

The current nature and regulation of retail services in restructured states may represent such a barrier that might inhibit reaching optimal levels of long-term capacity contracting in PJM. This is because a significant portion of retail load is supplied under regulated "default service" arranged by electric distribution companies ("EDCs") and overseen by the utility commissions. In restructured eastern PJM states, such as New Jersey and Maryland, the EDCs are required to procure bundled energy and capacity supplies for these default service obligations. The contracts for such default service procurement generally have durations of three years or less. This sole reliance on short- or intermediate-term contracts under state-regulated default service procurement appears to deviate significantly from the procurement and risk management practices of large competitive retail service providers.

Competitive retail service providers, including those in PJM, appear to secure a meaningful portion of their supplies through long-term contracts or even the acquisition of generating assets. Such actions are designed to counter the effects of perceived broken linkages between competitive retail and wholesale markets by reducing the transaction costs of securing long-term contracts and effectively vertically re-integrating load serving responsibilities with merchant generation. For example, Constellation's NewEnergy retail supply business obtains energy from a portfolio of various sources, including its own generation assets, contractually-controlled generation assets, exchange-traded bilateral power purchase agreements, unit-contingent power

purchases from generation companies, tolling contracts with generation companies, and spot purchases from the regional power markets.[70] This portfolio balances retail sales contracts that are reported to extend from one to ten years and beyond, although these will generally not be exactly matched by long-term capacity procurement contracts.[71] Constellation Energy explicitly stated that its strategic retail-service-operations objective is to buy generation assets in regions where the company does not have a significant generation presence and enter into longer-term agreements with merchant generators.[72] In fact, this objective was a primary reason for Constellation's purchase of generating plants in Texas as well as its recent acquisition of 2,950 MW of generating plants in ISO-NE, which "improved [Constellation's] net load to generation ratio to approximately 55 percent."[73] Direct Energy, another retail service provider, appears to have started pursuing a similar strategy through long-term contracting power from generation suppliers, buying physical generation assets, and even acquiring natural gas production, storage and transportation.[74] Similarly, NRG's recently announced acquisition of Energy Plus holdings was explained as an effort to "expand its retail marketing presence in the Northeast and Mid-Atlantic" to give the company "more of a retail presence to offset its generation assets in periods when wholesale power prices are depressed."[75] NRG's announcement also marked another retail acquisition following Constellation Energy Group's purchase of StarTex Power and its planned acquisition of MXenergy, and Direct Energy Services' purchase of Gateway Energy Services.[76]

We have not analyzed what fraction of total retail load should be supplied through long-term contracts or physical plant ownership. Such decisions will depend upon a company's tolerance for risk and expectations regarding future market conditions. While long-term contracts and physical plant ownership will stabilize procurement costs, they also create the risk that costs will be above market. However we believe it is possible that the most efficient amount and duration of long-term contracting may exceed the amount realized for load under default service procurement. We view this potential concern over whether default service creates a barrier to efficient contracting primarily as a matter for state commissions and state legislatures to examine in the context of retail choice and default service regulations. The best way to realize an efficient level of long-term contracting and asset ownership among retail providers might be for the states to reduce their reliance on default service. This would allow increased interaction between retail service providers and customers that would allow market participants to determine the most efficient retail supply portfolio. Reduced reliance on default service, for example, exists in Texas where most retail customers are served by competitive suppliers after default service was eliminated in 2007 (although a provider of last resort service is still available to customers who lose their competitive service providers).[77] A second option that states could pursue would be to review default service procurement practices to determine the extent to which longer-term

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70 See Constellation's 2010 10-K filing in Constellation (2011), Part 1, Item 1, pp. 4-5.

71 *Id.*

72 See Constellation (2010), pp. 29 and 60; Morningstar (2010).

73 For example, see Constellation (2010).

74 Direct Energy (2011).

75 Megawatt Daily, "NRG to buy Energy Plus Holdings for $190 mil," August 17, 2011.

76 *Id.*

77 Kiesling and Kleit (2009), Chapter 8.

contracts (procured on a non-discriminatory basis from existing or new resources) should be part of default service procurement.

Only if states fail to pursue these options and generation investment lags even as market prices reach or exceed Net CONE, it may be necessary for PJM to introduce mandatory long-term procurement of capacity into the RPM construct. However, we consider this to be a far less desirable option and would recommend pursuing this option only if (1) it becomes clear that a review and revision of default service procurement is unlikely, and (2) it can be determined with sufficient confidence that longer-term contracts through RPM-based resource procurement will actually be needed to assure resource adequacy at reasonable costs. We examine this option along with several alternatives more fully in Section VI.F.

5. Does the Electric Power Industry Need Long-Term Contracts?

There is a perception that new generation cannot be built without long-term PPAs or close to 10 years or more. As discussed above, this perception is largely created by current low-priced market fundamentals and the preference among developers to lay off risks onto contract counterparties. Reliance on long-term contracts is also rooted in the regulated past of the industry (including Qualifying Facilities under PURPA). However, a number of observations about customer preferences and contracting practices in other capital intensive industries suggest that widespread perceptions may overstate the need for long-term contracting as the industry evolves.

First, most retail customers are unwilling to commit to long-term contracts. The reluctance is not unique to restructured electric power markets. This is also the case for most energy commodities sold in retail markets, including commodities with even higher price uncertainty, such as gasoline. If contracts are signed in other retail market segments, they rarely go beyond the next season (*e.g.*, heating oil), or the next two years (mobile telecom service). In fact, long-term contracts between retail customers and suppliers are uncommon even in the most risky and capital intensive portions of the energy industry (such as oil and natural gas exploration), despite the unpredictable nature of risks (such as oil price movements based on a wide range of geopolitical influences, including cartel behavior).

Second, other capital-intensive industries with significant price risks generally require that investments are backed by companies with sufficient equity. However, such "balance sheet financing" of major investments is less common in the electric power industry.[78] While numerous examples of balance-sheet financing and generation investments without long-term PPAs or other long-term price hedges exist (including merchant wind power development),

[78] The use of balance sheet financing does not mean that medium- or long-term contracts are eliminated for these projects. Rather, it simply means that the role of medium or long-term contracts is reduced because at least some projects can be built with less of the project costs hedged through long-term contracts. Projects may be built without PPAs, shorter-term PPAs, or PPAs that cover only a portion of the project's expected sales.

project financing arrangements supported by long-term PPAs remain the first choice of most power plant developers.[79]

The lower reliance on balance sheet financing in the power industry does not mean that project developers in other industries would not prefer the lower risk and financing costs that they would be able to achieve if they had long-term sales agreements. Nor does it mean that power industry developers are unable to develop projects without long-term sales agreements. Rather, the relatively low levels of balance sheet financing in the power industry appears to be an artifact of industry evolution. Specifically, the merchant generation sector has evolved based on: (1) long-term PPAs with regulated utilities (starting with mandated qualifying facility (QF) contracts in the late 1980s and early 1990s); (2) project development efforts by small companies without much equity; and (3) a reliance on highly leveraged financing arrangements.

Third, competitive retail electricity providers and companies in other capital-intensive industries, including in oil and gas, also tend to be partially (but not fully) vertically integrated to manage risks and reduce transactions costs. They have bought physical assets or signed a portfolio of contracts to manage overall supply obligations and associated risks. Partial vertical (re)integration also appears to be becoming more prevalent in electricity markets. In the United Kingdom, for example, retail suppliers have re-integrated into the generation business.[80] Similarly, generation owners are integrating vertically into retail sales, as noted in the above discussion of NRG, Constellation, and Direct Energy, and with Exelon's proposed merger with Constellation as another recent example.[81] A transition to a partially integrated industry structure has a number of potential advantages and will reduce the need for, or compensate for the lack of, extensive bilateral contracting.[82] Competition will be maintained or enhanced because the companies have a reduced ability and incentive to exercise market power and, unlike in non-restructured markets, are not *fully* integrated and do not enjoy exclusive service franchises.[83]

Consistent with these observations, we believe the deregulated electricity industry will naturally migrate to a partially vertically integrated structure that, over time, will rely less on long-term

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79 For example, the DOE reports that in 2009, 38% of all new wind generation capacity was from merchant or quasi-merchant projects that relied on short-term contracts or hedged wholesale spot market sales rather than long-term PPAs. See Wiser, *et al.* (2010), p. 34.

80 In the U.K., for example, restructuring in the early 1990s resulted in completely vertically unbundled industry structure. Today, the six largest competitive retail suppliers (supplying 99% of retail load) also own approximately 70% of the installed generating capacity. See Ofgem (2010). Note, however, that such partial integration by large companies will also tend to make it more difficult for smaller and non-integrated suppliers to enter and compete in the market. (See Ofgem, *Liquidity Proposals for the GB wholesale electricity market*, February 2010, posted at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=95&refer=Markets/WhlMkts/CompandEff

81 See Exelon and Constellation (2011).

82 For a discussion of the implications of vertical re-integration of competitive retail service and generation companies, see Meade and O'Connor (2009); Mansur (2007) "Upstream Competition and Vertical Integration in Electricity Markets," 50 J. Law & Econ. 125. http://www.dartmouth.edu/~mansur/papers/mansur_vi.pdf.

83 See, for example, Bushnell, J. B., Mansur, E. T. & Saravia, C. (2008). "Vertical Arrangements, Market Structure, and Competition: An Analysis of Restructured U.S. Electricity Markets." American Economic Review, 98, 237-266.

PPAs to underwrite new generation development. We view these trends to reflect an efficient response to deregulation, which shifts the risks of potentially uneconomic generation investments away from customers and toward developers. As increasingly large and diversified companies, these developers will be in a better position to evaluate, manage, and bear these risks. Regulatory or legislative intervention to force long-term contracting in restructured markets, even if through RPM design, carries the risk of interfering with the natural evolution of the industry with the risk of adverse long-term consequences for the efficiency of future capacity expansion.

In short, we recognize that there may be many generation projects in PJM that cannot get financed and built under current market conditions. However, while some project developers may cast this as a market failure caused by the inadequacies of RPM or state retail choice constructs, we believe the primary reason that these projects cannot get financed and built is that they are not currently needed and are currently uncompetitive with alternative sources of capacity. In the future, when these projects *are* needed for resource adequacy, we believe that market prices will rise and will make these investments attractive. However, we also recognize that it will be beneficial to both suppliers and customers if long-term contracts are enabled and not hindered by the design of RPM and state retail regulation, topics which we examine further in Section VI.F on options for extending price certainty under RPM and in Section VI.E.1 on the minimum offer price rule (MOPR).

D. Equal Compensation for Old and New Generation

A number of stakeholder comments, primarily from state commissions, relate to concerns over why old generation and demand resources receive the same compensation as new generation under RPM. This topic also relates to stakeholder comments about their disappointment that RPM has served to keep online "old and dirty" generating plants while failing to get much (if any) new generation built in eastern PJM despite prices that were higher than in the western portion of the RTO. Some of these concerns have also been raised in a recent report prepared for the American Public Power Association ("APPA").[84]

As discussed in Section II, some new generating units have in fact been built under RPM. However, it is unclear that RPM itself induced these units to come online. Moreover, some stakeholders believe that more generation should have been built in eastern PJM where RPM prices have been higher than in the west. The main reason more generation did not enter is that it is not currently needed to maintain reliability requirements. Despite relatively higher prices in eastern PJM, these prices have been below the cost of new entry. The combination of lower peak loads, available existing generation, deferred retirements, capacity additions to existing generation, and expansion of demand response resources have made it possible to meet resource adequacy requirements at market prices below what would be needed to support the entry of more new generation.

In this section, we briefly address the environmental concerns about retaining old plants. We also discuss the differences in the time profile of capacity prices between regulated and restructure markets, and the feasibility and efficiency of differentiating capacity payments between new and existing plants.

[84] See Wittenstein and Hausman (2011).

1. Keeping "Old and Dirty" Plants Operational

State and federal legislatures and regulatory agencies set rules to reduce the environmental impacts of power generation. Recent regulations include the Regional Greenhouse Gas Initiative ("RGGI"), state renewable portfolio standards, the Maryland Healthy Air Act, and EPA regulations and related state implementation plans to meet tightening National Ambient Air Quality Standards ("NAAQS") and to reduce the output of hazardous air pollutants (HAPs).

We have not seen any evidence suggesting that existing plants are not complying with environmental regulations, even older units that have higher emission rates than new plants. Nor have we seen evidence indicating that wholesale capacity markets have contributed to greater emissions levels from these facilities. To the contrary, RPM recognizes the costs of the plants' environmental footprint in two ways. First, "dirty" plants that need to install control technology to comply with environmental regulations will include the costs of such investments in their capacity market offers. For example, in the 2014/15 auction, many resources needing environmental retrofits either opted not to offer or offered at higher levels, and not all cleared when other resources could provide capacity more cheaply, as discussed in Section II. Uncleared plants may consequently retire and the cleared resources will install pollution controls. Second, higher emissions rates result in higher allowance costs, which reduces the dispatch frequency and the energy margins these plants earn. This will reduce their emissions and tend to raise their capacity market offers (and the IMM's offer caps), which will make them more likely not to clear in RPM in the future. Thus, RPM internalizes both the variable and fixed costs of complying with existing and planned environmental regulations. With these costs internalized, the competitive wholesale markets facilitate compliance with environmental regulations at lower costs while still maintaining resource adequacy.

If there are any concerns over the remaining environmental footprint of existing generation assets, they should be addressed through stricter federal and state environmental standards. Otherwise, RPM cannot be expected to implement environmental standards that do not exist. Nor should RPM be expected to impose indirectly tighter environmental standards than state and the federal governments have deemed appropriate. In our opinion, RPM is performing well in terms of incorporating the costs of existing and planned environmental regulations. The adequacy of the environmental regulations themselves should not be a factor in the assessment of whether RPM is achieving its objectives.

2. The Time Profile of Capacity Prices in Restructured vs. Regulated Markets

The position that older plants should not be compensated for capacity at the same level as new plants is often related to a misunderstood or under-appreciated difference in the time profiles of capacity prices in regulated and fully-restructured power markets. While it is generally understood, for example, that the price a tomato farmer receives for his tomatoes does not depend on the age of his tractor, this paradigm does not apply in cost-of-service regulated industry. Under cost-of-service regulation, the price charged for a power plant is determined by its accounting costs. As a result, new plants will generally be more expensive than old plants, at least until major capital additions are needed at the old plant. This declining revenue profile for power plants in a cost-of service regulated environment does not exist in restructured markets. In restructured markets, even the administratively-determined cost of new entry is calculated as the "levelized" cost of a new plant, which creates a revenue path that is either constant over time

(if costs are levelized in nominal dollar terms) or increasing over time (if costs are levelized in real dollar terms). Long-term PPAs signed through competitive procurement similarly often have pricing paths that are either constant or increasing over time. This time profile of cost recovery means older plants are paid the same for the capacity they provide as new plants. The time profile differs substantially from the time profile under cost-of-service regulation, under which the cost of new plant exceeds their "levelized costs" during the early part of the plants' life but is lower during the latter years.

Moreover, in a cost-of-service regulated environment, retail rates will reflect the cost of generating capacity only after new generating resources are placed in service and reflected in utilities' rate bases. This means there can be a lag of several years before regulated retail rates reflect the addition of expensive new capacity resources. This lag causes a significant misalignment of retail prices and investment signals. Because demand continues to grow due to low rates, more new resources may be added to the system than will ultimately be needed when retail prices increase to reflect the added costs. This can lead to excess capacity, high regulated retail rates, and the risk of stranded costs or regulatory disallowances.

The time profile of capacity prices is quite different in restructured power markets. As in all other competitive markets, the market price for capacity will increase before new generating capacity needs to be added. As market participants perceive an approaching scarcity of generating capacity, market prices for capacity will increase and, in response, market participants will identify the lowest-cost resources that can operate profitably at the anticipated market prices. In order to invest in new generation, competitive suppliers must expect to receive high enough capacity prices over the plant's entire economic life (including later years when the plant is aging). If capacity prices are reflected in retail rates or are otherwise made available to demand-side resources, this market-determined portfolio of resources will also include demand-response resources. The fact that capacity prices increase before new resources are actually added to the system will dampen demand growth and reduce the resource need and long-term costs.

The fact that prices in eastern PJM have increased even before much new capacity has been added, has led some stakeholders to question the value and effectiveness of capacity market and restructuring in general. However, we believe the observed price path is consistent with market fundamentals and efficient market outcomes and will result in lower costs over the long term.

3. Differentiating Capacity Payments for New and Existing Resources

The very design of capacity markets or capacity payment mechanisms raises the question of whether all resources should receive capacity payments, or whether such payments should be limited to new resources and resources which would otherwise retire. Limiting capacity payments to new resources is appealing to some because at first glance it appears that it would reduce the total costs associated with such capacity payments. Arguments of this sort are deceptively attractive, but they fail to consider the long-term impacts that would undermine efficient market signals and ultimately increase system costs.

If a resource adequacy requirement is to be met through a market mechanism, whether a centralized capacity market or solely by relying on bilateral contracts, the capacity from all resources that can be used to satisfy the requirement will have the same capacity value. As a result, capacity revenues available to existing and new resources cannot be differentiated in such a market environment. Even if RTO-administered capacity markets were limited only to new

resources, the full market value of capacity would still be captured by all existing resources through bilateral contracts, assuming that the resources are not cost-of-service regulated or under existing fixed-priced contract.

When limiting capacity payments to new resources or existing resources that would otherwise retire, it is also necessary to recognize that a sizeable portion of the existing pool of resources would be forced to retire in the absence of capacity revenues. For example, we have shown in our 2008 RPM Report that in the six years before RPM was introduced in PJM, between 500 MW and 3,500 MW of generating resources retired each year.[85] After RPM was introduced, annual retirement dropped to a range of zero to 500 MW for the first five BRAs. More importantly, however, an analysis of market monitoring data showed that at least 30,000 MW of PJM's capacity resources were at risk for retirement in the absence of capacity payments due to revenue deficiencies in PJM's energy and ancillary services markets. This is not surprising considering that the going-forward costs of many existing resources can be high even in comparison to new resources. As a result, capacity auctions will generally select new capacity resources even when cost-based bids for many of the existing resources do not clear. For example, in PJM's auction for the 2011-12 planning year, a total of 2,337 MW of new capacity cleared in the auction, while 496 MW of new capacity did not clear.[86] In comparison, 4,600 MW of capacity from existing resources did not clear, even though the bid prices for the existing resources were mitigated to reflect their incremental costs. These data show that the all-in costs of retaining existing plants can even exceed the costs of new plants. This is because existing plants are sometimes more expensive, and keeping them operational may require significant ongoing costs (*e.g.*, high annual repair, refurbishment, and maintenance costs) as well as occasional substantial investments (*e.g.*, environmental retrofits or replacements of major plant components).

Only in power markets that do not impose resource adequacy requirements on LSEs can capacity payments be targeted specifically to new resources or the retention of existing resources. However, such a differentiation of payments between old and new generation would cause significant market distortions that, while potentially saving costs in the short-term, would result in substantial inefficiencies and higher costs in the long term.[87] Subsidizing the entry of new plants through above-market long-term contracts results in similar distortions and long-term costs. While these out-of-market mechanisms will suppress market prices in the short term, the market distortions they create will perpetuate and accelerate the need to expand the scope of such subsidies or other out-of-market solutions to maintain reliability. Again, this solution will likely be less efficient and more costly in the long-term.

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[85] Pfeifenberger and Newell, *et al.* (2008), p. 20.

[86] Pfeifenberger and Newell, *et al.* (2008), p. 36.

[87] For a case study of the adverse consequences of imposing different prices for "new" and "old" resources, refer to the discussion of inefficiencies, reduced investment incentives, and overall welfare losses resulting from the different regulation of prices for "old" and "new" natural gas prior to the implementation of the Natural Gas Policy Act of 1978 as discussed in Viscusi, Vernon, and Harrinton (2000), pp. 616-632.

E. RPM's Ability to Replace or Prevent High Environmental Retirements

Several stakeholders expressed concern about RPM's ability to replace or prevent excessive simultaneous retirements caused by EPA's new HAP MACT and other regulations. Indeed, the slew of regulations currently being promulgated is likely to impose major stresses on electricity markets and the supply chain for environmental control equipment. These challenges are being felt nationally and are not limited to PJM. The reason for particular concern about RPM is that it is a restructured market which, unlike traditionally regulated systems, lacks centralized resource planning. RPM includes "buy bids" for capacity (up to their price cap for existing capacity), but there is no guarantee that enough capacity will retained below that price cap or offered from new resources to replace potentially large amounts of retirements.

1. RPM Facilitates Retrofits and Procures New Capacity Economically

RPM is designed to procure enough capacity to meet resource adequacy targets and to do so in an economically efficient, market-based fashion. RPM facilitates retrofits by allowing offers from existing generation to include the cost of retrofits. If the offer clears, the resource will earn at least its offer price with the prospect of recovering its retrofit costs. Existing resources will not clear only if lower cost resources are available to replace it (or the price cap is hit, which is unlikely). If the resource is not offered at all, replacement capacity can be procured. RPM supports new entry through its 3-year forward period, which provides enough lead time for a variety of new resources to enter, including new demand-side resources, generation uprates, and new generation.[88] Furthermore, RPM's centralized clearing and pricing transparency facilitate efficient economic tradeoffs between all such resource options. RPM also includes three incremental auctions after each base auction, each of which provides opportunities to procure addition capacity.

So far, these provisions have worked as intended. RPM has successfully and economically supported resource adequacy, including when the Maryland Healthy Air Act was implemented in 2009/11 and under the challenging conditions presented by EPA's HAP MACT regulations partially reflected in the most recent BRA for the 2014/15 delivery year. In that auction, 3.2 ICAP GW of existing generation was excused from offering, up from 1.2 GW the prior year (with FRR excused and other excused resources likely withdrawn for environmental reasons); 10.6 ICAP GW cleared at higher prices above $50/MW-day (4.4 GW above $100/MW-day), reflecting the costs of scrubbers and other environmental retrofits; and 10.2 ICAP GW (including all new PJM members such as ATSI) of existing generation was offered but did not clear. Despite these reductions of capacity from existing generation, and sufficient replacement capacity was procured, largely in the form of demand side resources. Furthermore, there were new resource offers that did not clear but could have if they had been needed and prices had been higher. (See Section II).

2. The Future is Uncertain and Retirements Should be Monitored

So far, RPM has performed successfully under the challenges presented by EPA's HAP MACT regulation through the 2014/15 delivery year. However, RPM has not been tested with larger

[88] As discussed in Section III.C, concerns that RPM does not support new generation are largely unfounded.

amounts of simultaneous retirements within the LDAs. It is too early to tell how well RPM (or any other construct) will mitigate the retirement threats caused by the full slate of tighter new regulations planned to take effect between 2015 and 2018.

Additional emerging regulations on *air quality* to be effective during that period include likely tighter emission limits and regional/state caps on NOx and SO_2 due to EPA's expected revisions to air quality standards for ozone, particulate matters ($PM_{2.5}$), and SO_2. These air quality regulations will affect all fossil fuel generation plants, but especially coal- and oil-fired plants. Furthermore, EPA proposed regulations on *cooling water* intake structures at generation plants to reduce damage to aquatic organisms due to impingement and entrainment. Under the proposed rule, states will determine what specific controls (such as mesh screens or cooling towers) would be required to be installed at each covered generation facility (including nuclear, coal, gas and oil plants). EPA has also proposed regulations on handling and disposal of *combustion by-products* (such as ash) which may require additional equipment on coal plants and may essentially eliminate surface disposal of wet coal ash. Finally, EPA is expected to issue proposed rules this year for *greenhouse gas* ("GHG") performance standards applicable to new and modified generation plants. The impact of this new NSR rule on existing power plants will in part depend on EPA's interpretation of major modifications (*e.g.*, whether repairs are considered major modifications), which has been a central issue in numerous litigation cases between EPA and plant owners with respect to criteria pollutants. The combined and fairly simultaneous impacts of these emerging EPA regulations on air quality, cooling water, combustion by-products, and GHG will likely contribute to early retirements of a significant portion of the existing generation units over the next five years. Future CO_2 prices under a potential federal climate policy would additionally increase the retirement pressures on coal-fired plants.

Hence, despite RPM's design and success to date, it is not possible to predict exactly what will happen if a large number of plants retired simultaneously. Such simultaneous retirements would be a challenge in any system and could lead to difficult-to-manage spikes in retrofit costs. Given these risks, PJM will undoubtedly continue to monitor closely potential retirements through communications with generators and its own analysis.[89] Vulnerabilities identified could be used to ensure that the appropriate LDAs are being modeled and to check that sufficient new resources are being pre-qualified for the auctions. If not, both PJM and the states will need to pursue options to entice existing capacity to stay online or to procure new resources.

Another risk that PJM will need to monitor is the possibility that environmental regulations which force a large number of retrofits during a single year could produce spikes in RPM prices for a single auction, followed by price decreases in the next auctions to levels too low to allow for cost recovery of the retrofit investments. If that occurs, the offer cap provisions for environmental retrofits may have to be revisited. A number of the recommendations we present in the remainder of this report, such as more proactive modeling of LDAs, would provide additional safeguards to ensure RPM can address these challenges.

F. The Dependability of Demand Resources

PJM stakeholders, primarily generators, voiced a range of concerns regarding the dependability of demand-side resources. These stakeholders are concerned that DR development plans may

[89] See PJM (2011p); see also PJM (2011z) and ERCOT, MISO, NYISO, PJM and SPP (2011).

not be fulfilled if the market becomes saturated, that DR does not face the same obligations as does generation, that there is no historical record indicating how DR will perform as required at high penetration levels, and that these problems may become more acute as DR penetration rises and starts displacing larger amounts of generation.

1. Market Saturation Concerns about Planned DR

In the 2014/15 BRA, demand-side resources (DR and EE) accounted for 14.9 GW of capacity (UCAP), or 9.4% of total resources committed. This is 4.0 GW more than the demand-side capacity (DR and ILR) committed for the current 2011/12 delivery year. While the amount of DR capacity cleared for 2014/15 is impressive, we see no evidence that its performance should be considered speculative. First, to our knowledge demand-side resources committed for the current delivery year have been performing well during the recent heat waves. Second, while the 4.0 GW increase over the next three years compared to the current delivery year is ambitious, it is smaller than the 6.0 GW increase that occurred over the past three years. Third, demand resources are exposed to verification and penalty provisions for resource deficiencies and performance violations that are roughly similar to those of generation resources and should be sufficient to ensure performance. Finally, DR resources have exchanged their BRA commitments in incremental auctions at a rate no higher than generation resources and future incremental auctions will still be available as safeguards that would allow replacements of commitments that could not be fulfilled.

On the other hand, there is at least some indication that some providers may have overestimated their ability to enroll a sufficient number of customers to fulfill their DR capacity commitments in some areas. For example, one curtailment service provider ("CSP") filed a motion with the Public Service Commission of Maryland to amend its demand response capacity agreements with three utilities, after it encountered a number of problems attempting to contract with new customers to provide DR capacity required under those agreements for the 2011/2012 delivery year. The company cited "substantial competition from other providers also offering demand response services" as one of three reasons.[90]

To incentivize CSPs to offer only realistic amounts of "planned" DR and to develop them, RPM imposes deficiency penalties for failure to produce the resources or procure replacement capacity. As a possible additional safeguard to identify deficiencies early, PJM should consider monitoring development plans more closely, as discussed in Section VII.

2. RPM Design Issues for Accommodating Large Amounts of DR

The primary concern with relying on large amounts of DR (as a substitute for new generation resources) is that the frequency of potential calls increases as DR penetration rises. If DR resources are seasonally limited or contractually obligated to respond to dispatch instructions only a certain number of times, reliability could be compromised at higher levels of DR penetration. PJM has already addressed this concern by restricting the total amount of "Limited Summer" DR resources, introducing new DR products, and imposing minimum requirements for "Annual" and "Extended Summer" DR resources. We find this DR-related extension of RPM auction design to be a reasonable solution to the problem. Based on our

[90] Megawatt Daily, "Enernoc seeks amendments to Md. Contracts," June 30, 2011.

analysis presented in Section II of this report, we also find that this approach is working as intended.

Furthermore, if resources are found to underperform relative to their obligations in the future, they will face penalties similar to those imposed on generators. However, because large amounts of Annual DR is unlikely to be called very frequently under normal system conditions, it might be possible for a CSP to offer some limited resources as Annual resources without a high risk of being called upon and penalized if the resource cannot perform. To provide additional safeguards against such under-performance concerns, we recommend that PJM consider strengthening its verification processes by reviewing just prior to each delivery year whether DR resources would likely be able to respond as claimed. Such a review could include verifying the seasonal or annual nature of the load to be curtailed and whether there are any contractual limitations to the number of calls. These recommendations are discussed further in the context of comparability of DR and generation resources in Section VI.C of this report.

G. RPM TARGET PROCUREMENT

Stakeholders representing load and some of the state commissions raised concerns over the accuracy, economic efficiency, and transparency of reliability targets and load forecasts. A number of these concerns have also been raised publicly.[91] As stakeholders recognize, PJM's reliability targets and load forecasts determine the amount of capacity procured under RPM, both on an RTO-wide and LDA level. There are major implications for total annual capacity payments imposed on PJM load serving entities and capacity payments provided to generators. Under RPM, these payments can range from $5 billion to $15 billion annually and can vary significantly from one year to the next and from one LDA to the other based on market conditions, updates to LDA-internal resource adequacy requirements, and forecasts of future peak loads.

The RPM target procurement of capacity is a function of (1) the forecast of weather-normalized peak load for the RPM delivery year, and (2) the reliability requirement, which determines target reserve margins. At the RTO-wide level, PJM resource adequacy planning is based on a reliability requirement defined as the 1-day-in-10 years Loss of Load Expectation ("LOLE"). Within individual LDAs, the reliability requirement is determined based on a "conditional" LOLE target of 1-day-in-25 years, as explained below.

The purpose of RPM is to procure sufficient capacity so these reliability standards are satisfied on an RTO-wide and LDA-specific basis. As such, the scope of our RPM performance review

[91] For example, see Public Power Association of New Jersey, March 8, 2010 and December 2, 2010 letters to John Reynolds and Steven Herling re "Request for Consultant Review of PJM's Load Forecasting Methodology" from a group of residential, commercial and industrial consumers, state regulators and consumer protection agencies, and load-serving entities on the PJM system; Comments submitted on behalf of the Public Utilities Commission of Ohio in FERC Docket No. RM10-10, "Proposed Reliability Standard, BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 27, 2011; J.F. Wilson, "Reconsidering Resource Adequacy (Part 1): Has the One-Day-in-Ten-Years Criterion Outlived Its Usefulness?," Public Utilities Fortnightly, April 2010 and "Reconsidering Resource Adequacy (Part 2): Capacity Planning for the Smart Grid," Public Utilities Fortnightly, May 2010; and J.F. Wilson, "Review of CETO Methodology: LDA LOLE Criterion ('One Day in 25 Years'), presentation to RAAS, April 7, 2011.

includes an evaluation of how well RPM is meeting that goal, not the reliability target that RPM is designed to achieve. However, given the concerns articulated by stakeholders, we recommend that PJM consider re-examining the economic efficiency and cost-effectiveness of RPM reliability targets, in particular the methodology to determine LDA-specific reliability targets.

We also recommend that PJM increase the transparency and stakeholder understanding of the load forecasting process. However, we address load forecasting separately, in Section VI.B of our report, since increasing the transparency of the load forecasting process and increasing market participants' understanding of load forecasting uncertainties would also increase RPM price transparency and reduce RPM-related risks associated with load forecasts as one of the main administratively-determined RPM parameters.

1. The Use of RTO-wide Reliability Targets to Define the VRR Curve

On an RTO-wide basis, the VRR curve is anchored at the target reserve margin plus one%. The target reserve margin is based on a reliability target defined as a 1 day in 10 years Loss of Load Expectation (LOLE). The reasonableness of the 1 day in 10 year standard was reaffirmed by FERC earlier this year.[92] However, the FERC order also emphasized that "the one day in ten years criterion is one common approach for resource adequacy assessment, and by approving this regional Reliability Standard, the Commission does not establish the one day in ten years criterion to be the de facto, or the only acceptable metric for resource adequacy assessment."[93] The Commission further noted that it did "not disagree with commenters' arguments that the one day in ten years criterion could be improved."[94] Some PJM stakeholders also suggested that the standard should be improved, particularly because the economic rationale for the current standard has not been widely discussed. Moreover, stakeholders' doubts about the reliability standard itself seem to undermine their confidence in the efficiency and cost effectiveness of RPM.

As we already noted in our 2008 RPM Report, cost-effective reliability targets will not be entirely independent of the cost of capacity. As the cost of capacity increases, customers presumably would be willing to accept a slightly lower level of reliability. In other words, the economically-efficient demand for reserve capacity will tend to decrease as the cost of that capacity increases—a relationship which can be expressed by a sloped demand curve for reserve capacity. This demand curve for reliability would procure, at least theoretically, an optimal reserve margin that decreases as the cost of adding capacity increases.

To assess this "demand" for reserve capacity and derive an economically-efficient reserve margin target would require a detailed assessment of the value of incremental planning reserves. Others have suggested that the value of additional reserves is equal to the customers' Value of Lost Load ("VOLL"), such that an optimal reserve margin could simply be derived by estimating VOLL, the degree to which additional capacity reduces the expected amount of customer curtailments (*i.e.*, the Expected Unserved Energy or "EUE"), and the cost of additional

92 FERC Order No. 747, Planning Resource Adequacy Assessment Reliability Standard, 134 FERC ¶ 61,212 (issued March 17, 2011).

93 *Id.* at ¶31.

94 *Id.* at ¶32.

capacity.[95] However, this is not quite the case. The value of increasing planning reserve margin also includes a number of economic benefits in addition to reducing the amount of curtailed load.[96] As was seen during the California energy crisis, the primary economic consequence of reliability-related events is not necessarily the frequency or duration of firm load shed events, but excessively high power costs. Thus, the economic value of increased reserve margins also includes the high cost of emergency supplies procured or dispatched to avoid customer load curtailments as well as the insurance value of reducing the likelihood of extremely high-cost outcomes. For example, adding a combustion turbine to the system not only reduces the risk of curtailing load during emergency conditions, it also reduces production costs by allowing the dispatch of the turbine whenever the dispatch or opportunity cost of dispatching alternative resources would exceed the dispatch cost of the turbine—including high-cost imports, DR capacity with high dispatch costs, generation dispatched within their emergency limits, or energy-limited resources with high opportunity costs. In fact, these benefits of additional resources can be more important to the determination of economically efficient reserve margins than the value of VOLL, which is difficult to measure and ranges widely across customer types.

Unfortunately, these additional energy cost and risk mitigation benefits of higher reserve margins are also not yet widely understood. Moreover, an explicit analysis of the tradeoff between the marginal benefits and marginal costs of additional capacity is not routinely performed to determine reliability requirements.[97] We have recommended in our 2008 RPM Report that PJM and stakeholders examine the tradeoffs between reliability targets and the cost of new capacity as part of a broader re-evaluation of the level and application of current reliability criteria. While outside the scope of our RPM review, we believe such a study would still be helpful because it would (1) examine the tradeoff between the costs of incremental capacity and the benefits of that capacity including reliability, reduced energy costs, and reduced emergency purchases; (2) inform stakeholders about the value customers are receiving in exchange for paying for reserve capacity; (3) compare the 1-in-10 reliability standard to an economically efficient target; and (4) help determine the natural slope of the demand curve based on a cost-effective tradeoff between target reserve margins and the expected level of and uncertainty of in total reliability-related costs.

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95 For example, see J.F. Wilson, "Reconsidering Resource Adequacy (Part 1): Has the One-Day-in-Ten-Years Criterion Outlived Its Usefulness?," Public Utilities Fortnightly, April 2010 and "Reconsidering Resource Adequacy (Part 2): Capacity Planning for the Smart Grid," Public Utilities Fortnightly, May 2010; R. Borlick, Comments in FERC Docket No. RM10-10, "Proposed Reliability Standard, BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation," December 27, 2011.

96 Carden, Pfeifenberger and Wintermantel, "The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On," National Regulatory Research Institute Report 11-09, April 2011.

97 We are aware of only a few examples of recent analyses to determine economically efficient reserve margins, including studies by Southern Company, the Tennessee Valley Authority, and Louisville Gas & Electric.

2. The 1-in-25 Standard for Setting LDA-Level Reliability Targets

Stakeholders have raised concerns specifically about the reasonableness of the reliability standard that is applied to individual LDAs.[98] The LDA-level reliability requirement based on the 1-day-in-25 years standard also is a major determinant of RPM auction outcomes within LDAs and—in interaction with other administrative parameters such as CETL, transmission planning decisions, and load forecasts—a significant factor contributing to administrative uncertainty of LDA capacity prices.

As we explained in our 2008 RPM Report, reliability targets within individual LDAs, which define LDAs' transmission import objectives (CETO), are set based on an LOLE of 1 day in 25 years. This is a *conditional* LOLE, because the LDA's imports are treated as if they were 100% available, in spite of the fact that neither the transmission capability into the LDA nor PJM generation outside the LDA is guaranteed to be 100% available in actual operations. The *unconditional* LOLE for the PJM footprint is 1 day in 10 years, which includes the possibility that generation supply is inadequate (but assuming unlimited transmission within the PJM footprint). This means that within an LDA the combined LOLE target is approximately the sum of (1) one day in ten years; plus (2) one day in 25 years; plus (3) the LOLE associated with transmission line outages or derates.[99] This means that within transmission constrained LDAs, the total LOLE is at least 1.4 days in ten years,[100] depending on the transmission dependence of the LDA.

We recommended in our 2008 RPM Report that PJM evaluate whether the 1-in-25 year conditional LOLE target, which is invariant with the transmission dependency of individual LDAs, is reasonably optimal. We understand that PJM is already in the process of reviewing the 1-in-25 standard with its stakeholders and recommend continuation of this effort.

It is likely that a more refined determination of LDAs' LOLE targets would result in targets that vary with the degree of each LDA's import dependence. Presumably, an LDA that is highly reliant on imports would have a more stringent target (recognizing that the assumption that imports are 100% available is particularly optimistic) than an LDA that is less dependent on imports. A more refined determination of LDAs' reliability requirements may be achievable by studying PJM-wide resource adequacy through multi-area reliability simulations that consider the reliability of transmission import capabilities and simultaneously determine both footprint-wide and LDA specific LOLE levels. Such multi-area reliability modeling could also be combined with economic reliability simulations that would assess the economic tradeoffs between the cost and value of additional reliability.

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98 J.F. Wilson, "Review of CETO Methodology: LDA LOLE Criterion ('One Day in 25 Years')", presentation to RAAS, April 7, 2011.

99 See PJM (2011x), Section 4.

100 $1/10 + 1/25 = 0.14$ days per year = 1.4 days in 10 years.

IV. ANALYSIS OF NET COST OF NEW ENTRY

In this section of our report we analyze the Net Cost of New Entry (Net CONE) as used in RPM. We first present the results of our concurrent study updating engineering-based estimates for the gross cost of new entry (CONE) for the 2015/16 delivery year. Detailed documentation of these CONE estimates is provided in our separate report and associated data files. We present here the summary of our recommended CONE estimates for simple-cycle and combined-cycle plants for each of the five PJM CONE Areas.

We provide these CONE estimates for consideration by PJM and stakeholders according to the PJM Tariff, which requires that CONE be fully reevaluated every three years while the other years are updated by trending the previous CONE estimate based on the Handy-Whitman index.[101] The new CONE estimates, if adopted, would be used as a key parameter defining the VRR curve and as inputs to mitigation thresholds under the Minimum Offer Price Rule (MOPR).

Section IV.B analyzes the energy and ancillary services (E&AS) offset used in determining Net CONE. We examine the accuracy of the administratively-determined historical E&AS offset compared to the E&AS margins actually earned by generating units similar to the reference technology. We also evaluate two potential changes to the E&AS methodology, including: (1) whether the E&AS offset should be a backward-looking, forward-looking, or equilibrium estimate; and (2) whether the new scarcity pricing mechanisms, when implemented, would warrant any adjustments to the E&AS approach including possible true-up mechanisms.

Finally, this section of our report briefly examines the prices at which new generating units have offered into RPM to evaluate the feasibility of determining Net CONE empirically based on these offer data.

A. Gross Cost of New Entry

Updated CONE estimates are needed once every three years for PJM and stakeholder review. These estimates, if adopted, would be used for two purposes: (1) to calculate Net CONE (in conjunction with the administratively-determined E&AS offset) to define the price points of the VRR curve; and (2) as the basis for calculations to screen for and mitigate capacity offers from new generators that may be uncompetitively low according to the MOPR, as discussed further in Section VI.E. The detailed engineering cost study summarized here is presented in our separate report, *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM* (CONE Report).

After summarizing the results of our CONE Report, we explain our recommendation to continue using a combustion turbine (CT) as the marginal resource type to be used as the reference technology for estimating Net CONE. We also examine the implications of using a "level-nominal" versus a "level-real" cost annualization method for determining CONE. We recommend that PJM and stakeholders consider transitioning to a level-real approach to reflect projected escalation in future CONE values and associated market prices due to continued

[101] See PJM (2011q), pp. 2278-2280.

escalation of the capital cost of new plant. This recommendation, however, is contingent upon combining it with our recommendations to calibrate the E&AS offset (Section IV.B) and increase the cap of the VRR curve to address identified RPM performance concerns (Section V).

1. Levelized Cost Estimates of a New Simple-Cycle and Combined-Cycle Plant

As discussed in the CONE Report, our effort to estimate the levelized costs of new entry includes:

- A screening and siting study to determine the appropriate technology type and county to use as the basis for our cost estimate in each CONE Area;
- Details on the reference plant performance and technical specifications;
- An engineering cost estimate by CH2M HILL of the plant-proper engineering, procurement, and construction (EPC) costs and major equipment costs;
- Owner's costs incurred during project development, construction, and operations;
- An estimate by Wood Group of the ongoing fixed operations and maintenance ("FOM") costs that would be incurred by such a plant; and
- A study of the appropriate cost of capital for a merchant developer in PJM, for use in annualizing plant capital costs.

Here we simply summarize (1) the selected plant specifications that were used as the basis for developing our estimates and (2) the resulting capital costs of that study in comparison with the most recent previous CONE studies.

Table 14 and Table 15 contain the summary siting and plant specifications used as the basis for the CT and CC CONE estimates in each CONE Area. To determine the site locations shown in Table 14 we first selected locations with access to high voltage transmission infrastructure and at least one major gas pipeline. Among counties with sufficient infrastructure, we identified both the locations with the highest number of gas CCs and CTs recently built or under construction, and whether industrial land is currently available in those locations. Site selection for the SWMAAC CONE Area proved more difficult due to both a lack of recent new entrants (or units under construction) and a lack of vacant industrial land in many parts of Maryland. For SWMAAC we selected Charles County, Maryland based on: (1) gas and electric infrastructure availability; (2) the availability of vacant industrial land as indicated by property listings; and (3) Charles County is the location of the only permitted large gas facility proposed in SWMAAC, which is the 640 MW CPV St. Charles project.[102]

[102] Data on recent gas CC and CT builds based on Ventyx (2011).

Table 14
Site Specifications for CONE Estimates by CONE Area

CONE Area	Sited Plant Location		Interconnection	Gas Pipeline Infrastructure Available
	County	*Zone*	*(kV)*	
1 Eastern MAAC	Middlesex, NJ	JCPL	230	Transco, Texas Eastern
2 Southwest MAAC	Charles, MD	PEPCO	230	Dominion Cove Point
3 Rest of RTO	Will, IL	COMED	345	ANR, NGPL, Midwestern, Guardian/Vector
4 Western MAAC	Northampton, PA	PPL	230	Transco, Columbia
5 Dominion	Fauquier, VA	DOM	230	Transco, Columbia, Dominion

Source: CONE Report, pp. 8.

The reference plants' technical specifications are summarized in Table 15. CH2M HILL used these plant specifications as the basis for engineering estimates of plant construction costs. These specifications were chosen to most closely reflect the types of projects that have been built recently or are currently under construction. Design details, such as the type of environmental controls and dual-fuel capability, were based on both an analysis of recent plant additions and an assessment of environmental compliance requirements.

The chosen simple-cycle reference technology is a plant with 2 GE 7FA.05 turbines, fitted with selective catalytic reduction (SCR) in all CONE areas other than Dominion. The net summer capability of these CT plants is 390 MW (392 MW without an SCR). The combined-cycle reference technology is a 2×1 plant using GE 7FA.05 turbines, fitted with an SCR. The net summer capability of these CC plants is 584 MW at baseload or a maximum 656 MW when duct firing. For both the CC and CT, all facilities are equipped with dual-fuel capability in all locations except CONE Area 3 representing the unconstrained RTO (*i.e.*, western portions of PJM). We also provide estimates for adding dual-fuel capability in CONE Area 3 and adding SCRs in the Dominion CONE Area.

The installed and annualized cost estimates for these reference CT and CC plants are presented in Table 16 and Table 17 in 2015 dollars. These tables also compare our results with the most recent PJM CONE studies conducted by Power Project Management, LLC in 2008, inflation adjusted to 2015 dollars. The overnight capital cost estimates in these tables include all EPC contractor costs, major equipment costs, and other owner's costs incurred during project development and construction. The majority of these capital costs were estimated by CH2M HILL using the same cost estimation methods that they apply when bidding on projects as an EPC contractor. We independently developed a subset of owner's capital costs that are not included in the CH2M HILL estimates, including electric and gas interconnection costs based on costs actually incurred by recent projects. Estimates of ongoing fixed O&M costs are based on O&M fee estimates from Wood Group and our own estimates of other owner's costs, such as plant insurance and property taxes.

Table 15
Plant Technical Specifications for the Reference CC and CT

Plant Characteristic	Simple Cycle	Combined Cycle
Turbine Model	GE 7FA.05	GE 7FA.05
Configuration	2 x 0	2 x 1
Net Plant Power Rating	CONE Areas 1-4 (w/ SCR): 418 MW at 59 °F 390 MW at 92 °F CONE Area 5 (w/o SCR): 420 MW at 59 °F 392 MW at 92 °F	Baseload (w/o Duct Firing): 627 MW at 59 °F 584 MW at 92 °F Maximum Load (w/ Duct Firing): 701 MW at 59 °F 656 MW at 92 °F
Cooling System	n/a	Cooling Tower
Power Augmentation	Evaporative Cooling	Evaporative Cooling
Net Heat Rate (HHV)	CONE Areas 1-4 (w/ SCR): 10,094 btu/kWh at 59 °F 10,320 btu/kWh at 92 °F CONE Area 5 (w/o SCR): 10,036 btu/kWh at 59 °F 10,257 btu/kWh at 92 °F	Baseload (w/o Duct Firing): 6,722 btu/kWh 59 °F 6,883 btu/kWh 92 °F Maximum Load (w/ Duct Firing): 6,914 btu/kWh at 59 °F 7,096 btu/kWh at 92 °F
NOx Controls	Dry Low NOx Burners Selective Catalytic Reduction (Areas 1-4) Water Injection for DFO (Areas 1-2, 4-5)	Dry Low NOx Burners Selective Catalytic Reduction Water Injection for DFO (Areas 1-2, 4-5)
Dual Fuel Capability	Single Fuel (Area 3) Distillate Fuel Oil (Areas 1-2, 4-5)	Single Fuel (Area 3) Distillate Fuel Oil (Areas 1-2, 4-5)
Blackstart Capability	None	None
On-Site Gas Compression	None	None

Sources: CONE Report, pp. 18.

Estimating the annual revenues required to cover the investment and other fixed costs of a new plant requires translating the plant's investment costs into annualized costs. In a regulated cost-of-service environment, this stream of annualized costs is based on accounting costs, including depreciation expenses, debt service expenses, taxes, and the allowed return on equity. In restructured, competitive markets, annualized costs are often based on what is referred to as "levelized" costs. Levelized costs are calculated such that receiving net revenues equal to these levelized costs over the cost-recovery period (here 20 years) provides sufficient funds to recover the investment, a return on the investment, taxes, and other fixed costs. Such levelized costs are often the basis for the contract price in long-term power purchase agreements, which may be structured as annual payments that are constant over the contract duration or as annual payments that increase over time. Such contract escalation rates are often tied to the expected inflation rate.

A calculation of levelized capital costs requires an estimate of generation developer's financing costs. We recommend financing parameters consistent with the costs of a merchant generator using balance sheet financing without a long-term power purchase agreement (PPA). To the extent generation projects would be developed with long-term contracts, this would reduce

overall financing costs because investment-related risks would be transferred to the contract counterparty. As discussed in Section III.C, the lower risk with a PPA reduces financing costs because it allows for financing with a higher proportion of debt and reduces the costs of project-related debt and equity. However, the financing costs of such a highly-leveraged project would be inappropriate as a benchmark for determining the cost of new entry. We believe CONE estimates should represent the costs of a merchant plant exposed to the revenue uncertainty in PJM's capacity market.

As documented in our CONE Report, we estimate these financing costs of a merchant plant to be equal to an 8.5% after-tax weighted average cost of capital. This is equivalent to 50 percent debt and equity financing at a 12.5% cost of equity, a 7.5% cost of debt, and an approximately 40% combined federal and state tax rate.[103] As shown in our CONE Report, this cost of capital estimate is derived for a sample of publicly-traded merchant generation companies and is consistent with financing cost data from a number of independent sources, including fairness opinions prepared by investment banks in the context of recent mergers and acquisitions. In addition to these cost of capital estimates and discussed further in our CONE Report, levelized cost estimates are based on a cost recovery period of 20 years, Modified Accelerated Cost Recovery System ("MACRS") schedules consistent with industry practice and the previous PJM CONE studies,[104] and our estimate of a 2.5% long-term inflation rate.

Table 16
Installed and Levelized Cost Estimates for 2015/16: Reference Combustion Turbine

CONE Area	Total Plant Capital Cost *($M)*	Net Summer ICAP *(MW)*	Overnight Cost *($/kW)*	Fixed O&M *($/kW-y)*	After-Tax WACC *(%)*	Levelized Gross CONE: Level Real *($/kW-y)*	Levelized Gross CONE: Level Nominal *($/kW-y)*	PJM 2014/15 CT CONE *($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI for 1 Year*
June 1, 2015 Online Date (2015$)								
1 Eastern MAAC	$308.3	390	$791.2	$15.7	8.47%	$112.0	$134.0	$142.1
2 Southwest MAAC	$281.5	390	$722.6	$15.8	8.49%	$103.4	$123.7	$131.4
3 Rest of RTO	$287.3	390	$737.3	$15.2	8.46%	$103.1	$123.5	$135.0
4 Western MAAC	$299.3	390	$768.2	$15.1	8.44%	$108.6	$130.1	$131.4
5 Dominion	$254.7	392	$649.8	$14.7	8.54%	$92.8	$111.0	$131.5
Power Project Management, LLC 2008 Update								
June 1, 2008 Online Date (Escalated at CPI from 2008$ to 2015$)								
1 Eastern MAAC	$350.3	336	$1,042.2	$17.2	8.07%	n/a	$154.4	n/a
2 Southwest MAAC	$322.1	336	$958.4	$17.5	8.09%	n/a	$142.8	n/a
3 Rest of RTO	$332.5	336	$989.4	$15.3	8.11%	n/a	$146.1	n/a

Sources and Notes:

Overnight costs are the sum of nominal dollars expended over time and exclude interest during construction.

Dominion estimate excludes an SCR; with SCR CONE increases to $100.8/kW-year level real and $120.6/kW-year level nominal.

Rest of RTO CONE is for single fuel; dual-fuel CONE would be $110.7/kW-year level real and $132.5/kW-year level nominal.

PPM's estimates from Power Project Management (2008).

PPM's numbers are escalated according to historical inflation over 2008-2011 and at 2.5% inflation rate over 2011-2015, see CONE Report Section VI.A.

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103 We use slightly different cost of capital rates in different states consistent with the state income tax rate in each location.

104 See, for example, Power Project Management (2008) and Pasteris (2011).

Table 17
Installed and Levelized Cost Estimates for 2015/16: Reference Combined Cycle Plant

CONE Area	Total Plant Capital Cost *($M)*	Net Summer ICAP *(MW)*	Overnight Cost *($/kW)*	Fixed O&M *($/kW-y)*	After-Tax WACC *(%)*	Levelized Gross CONE: Level Real *($/kW-y)*	Levelized Gross CONE: Level Nominal *($/kW-y)*	PJM 2014/15 CC CONE *($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI for 1 Year*
June 1, 2015 Online Date (2015$)								
1 Eastern MAAC	$621.2	656	$947.5	$16.7	8.47%	$140.5	$168.1	$179.6
2 Southwest MAAC	$537.2	656	$819.3	$16.6	8.49%	$123.3	$147.5	$158.7
3 Rest of RTO	$599.0	656	$913.5	$16.0	8.46%	$135.5	$162.1	$168.5
4 Western MAAC	$597.4	656	$911.1	$15.8	8.44%	$135.1	$161.8	$158.7
5 Dominion	$532.9	656	$812.8	$15.4	8.54%	$120.2	$143.8	$158.7
Pasteris 2011 Update								
June 1, 2014 Online Date (Escalated at CPI from 2014$ to 2015$)								
1 Eastern MAAC	$710.9	601	$1,183.1	$18.5	8.07%	n/a	$179.6	n/a
2 Southwest MAAC	$618.7	601	$1,029.5	$18.8	8.09%	n/a	$158.7	n/a
3 Rest of RTO	$678.0	601	$1,128.3	$16.9	8.11%	n/a	$168.5	n/a

Sources and Notes:

Overnight costs are the sum of nominal dollars expended over time and exclude interest during construction.

Rest of RTO CONE is for single fuel; dual-fuel CONE would be $138.9/kW-year level real and $136.3/kW-year level nominal.

Pasteris Energy's 2011 CONE estimates were used as the basis for the CC CONE estimate for the 2014/15 delivery year, see Pasteris Energy (2011), pg. 55.

Pasteris Energy's numbers are escalated at 2.5% inflation rate, see CONE Report Section VI.A.

Table 16 and Table 17 report two sets of levelized cost estimates, one based on "level-nominal" and the other based on "level-real" cost recovery. The level-nominal cost recovery reflects levelized payments that are constant over time in nominal dollar terms, which means they do not increase over time with factors such as inflation. In contrast, level-real cost recovery reflects levelized payments that are constant in inflation-adjusted real terms, which means they are assumed to increase with our estimated long-term average inflation rate of 2.5%.

PJM's calculation of CONE is currently based on the level-nominal approach, although level-real costs were used for the purpose of the MOPR until recent changes to MOPR switched to the level-nominal approach to annualize costs. As we explain in more detail below, we believe setting CONE equal to level-nominal costs will overstate annualized costs over time and, as a result, could lead to over-procurement under RPM—assuming administratively-determined E&AS offset are accurate.

2. Selection of Resource Type to be Used as the Reference Technology

We recommend maintaining a CT as the reference technology for the determination of Net CONE for purpose of defining the VRR curve based on several considerations. First, RPM is designed to achieve capacity prices approximately equal to prices one would expect in a long-run market equilibrium. Over time, multiple resource types will be needed including baseload, intermediate, and peaking units. In a market equilibrium, all of these resources will have the same Net CONE. As a result, the choice of reference resource type would not matter as long as the resource type is among those that are economically viable and Net CONE is accurately calculated.

Second, Net CONE for each resource depends on both Gross CONE and the E&AS margin the generating units can expect to earn. Of these two components, estimates of Gross CONE will tend to be more stable, less uncertain, and less dependent on administrative assumptions. Therefore, to minimize the impact of administrative assumptions and uncertainty, it is preferable to choose the economically-viable reference resource type with the lowest E&AS offset. We believe CT technology meets this consideration. While demand resources may have even lower E&AS margins than a CT due to even fewer dispatch hours, there is no standard DR "technology" and its capital costs cannot be determined reliably.

Finally, even if a different technology were to be more economic than a CT under current market conditions, it would be inappropriate to opportunistically switch technologies based on temporary market conditions. While this would reduce average Net CONE values, actual plants do not have an option to switch type, which means no plant would be able to fully recover its fixed costs in the long run unless additional adjustments were made.

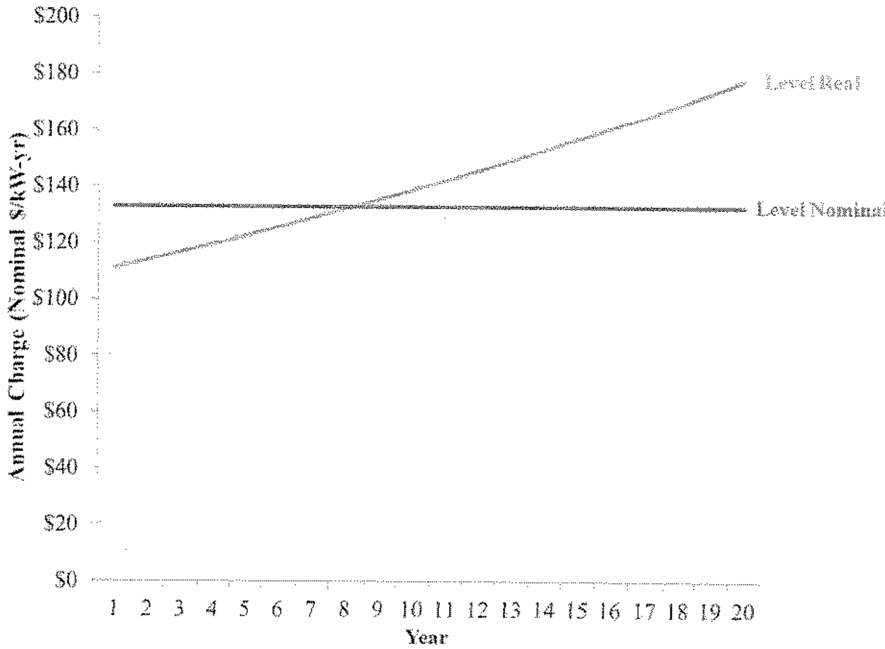
3. The Choice between Real and Nominal Cost Levelization

Translating investment costs into annualized costs for the purpose of setting annual capacity prices requires an assumption about how annual payments will likely be received over time to cover the investment and other fixed costs of generating plants in a market environment. Figure 14 shows two such possible time paths for our updated cost estimates of a CT in EMAAC as summarized in Table 16. It shows that "level-nominal" cost recovery implies constant annualized gross CONE of $134/kW-year ($367/MW-day) over the entire 20-year cost recovery period. In contrast, the "level-real" cost recovery path for the CT in EMAAC starts at an annual cost of $112/kW-year ($307/MW-day) in the first year, with expected payments in subsequent years increasing at the 2.5% rate of inflation. The present value of these two revenue streams is the same, both being exactly equal to the sum of investment and fixed O&M cost. This means both cost recovery paths provide for full recovery of all fixed costs, including financing costs.

Full cost recovery could also be achieved with cost recovery paths that deviate from the particular slopes of these level-nominal and level-real cost recovery paths. For example, a third levelization option could be based on technology-specific payment trajectory, such as the forecast inflation of CT plants rather than the economy-wide inflation.

The choice among level-nominal, level-real, and this third technology-specific cost recovery profile depends on how RPM-based capacity payments are expected to evolve. For example, if the cost of a CT plant is expected to increase with the rate of inflation—which would mean Net CONE estimates and offers by new entrants would increase at the same rate—investors would anticipate that, on average, RPM capacity prices would increase at that same rate as well. In this case, setting CONE equal to the level-nominal cost for each delivery year over time will over-compensate capacity resources over the course of their economic life. The annual average amount of overcompensation would be approximately equal to the difference between the starting values of the level-nominal and level-real cost recovery paths shown in Figure 14.

Figure 14
Comparison of Cost Recovery Paths for a New CT Plant



If, on the other hand, the cost of new plants and the associated CONE value are expected to increase over time at an average rate equal to the rate of inflation, then setting CONE equal to the starting point of level-real costs for each delivery year would, over time, result in a payment stream that matches the level-real cost recovery requirements exactly. Such an outcome, however, would only be possible if there are no offsetting factors, such as E&AS revenue losses of existing plants relative to increasingly more efficient new plants.

Because CT cost inflation net of E&AS losses relative to new plants may either fall short or exceed general inflation rates, setting CONE equal to level-real costs may under- or overcompensate resources over time. The level-real approach would *under*compensate plants over time if: (1) CT costs increase by less than inflation; or (2) CT costs increase with inflation but CTS built today experience E&AS revenue erosion relative to new CTs built in the future. The level-real approach, however, could *over*compensate if CT cost increases (net of E&AS revenue erosion) exceed general inflation rates. However, if CT costs net of E&AS revenue erosion are expected to increase at all over time, setting CONE equal to level-nominal costs will always overcompensate new plants over time.

To develop a recommendation concerning the choice between these levelization approaches, we have further explored these factors. We first compared the cost trends for CT and CC plants over time by comparing the annual increases of the Handy-Whitman index for turbogenerators with annual inflation rates from the consumer price index (CPI). As Table 18 shows, the annual average cost increases for turbine generators been approximately equal to inflation over the last 50 years, approximately 60 basis points above average inflation rates over the last 20 years, and approximately 150 basis points above inflation over the last 10 years. Note, however, that the rate of cost increase over the last 10 years has not been constant: CT costs have increased much faster between 2003 and 2008, but have decreased since then.